UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

Form 10-Q

(Mark One)

[X] QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the quarterly period ended June 30, 2003

OR

[ ] TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the Transition Period from to

Commission File No. 1-11680

GulfTerra Energy Partners, L.P.

(Exact Name of Registrant as Specified in its Charter)

Delaware (State or Other Jurisdiction of Incorporation or Organization)	**76-0396023** (I.R.S. Employer Identification No.)
4 Greenway Plaza **Houston, Texas** (Address of Principal Executive Offices)	**77046** (Zip Code)

Registrant's Telephone Number, Including Area Code: **(832) 676-4853**

Former telephone number: **(832) 676-6152**

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes ☑ No ☐

Indicate by check mark whether the registrant is an accelerated filer (as defined in Rule 12b-2 of the Exchange Act). Yes ☑ No ☐

The registrant had 49,794,421 common units outstanding as of August 7, 2003.

PART I — FINANCIAL INFORMATION

Item 1. Financial Statements

GULFTERRA ENERGY PARTNERS, L.P.

CONDENSED CONSOLIDATED STATEMENTS OF INCOME
(In thousands, except per unit amounts)
(Unaudited)

	Quarter Ended June 30,		Six Months Ended June 30,	
	2003	2002	2003	2002
Operating revenues	$310,109	$120,489	$589,035	$182,033
Operating expenses				
Cost of natural gas, oil and other products	158,463	27,343	298,047	39,501
Operation and maintenance	48,551	29,253	89,195	43,693
Depreciation, depletion and amortization	24,846	18,116	48,543	30,665
(Gain) loss on sale of long-lived assets	363	—	257	(315)
	232,223	74,712	436,042	113,544
Operating income	77,886	45,777	152,993	68,489
Other income (loss)				
Earnings from unconsolidated affiliates	2,987	4,012	6,303	7,373
Minority interest expense	(47)	(5)	(80)	(5)
Other income	309	435	692	861
Interest and debt expense	31,838	21,534	66,324	33,292
Loss due to write-off of debt issuance costs	—	—	3,762	—
Income from continuing operations	49,297	28,685	89,822	43,426
Income from discontinued operations	—	60	—	4,445
Cumulative effect of accounting change	—	—	1,690	—
Net income	$ 49,297	$ 28,745	$ 91,512	$ 47,871
Income allocation				
Series B unitholders	$ 3,898	$ 3,630	$ 7,774	$ 7,182
General partner				
Continuing operations	$ 15,856	$ 10,799	$ 30,716	$ 19,490
Discontinued operations	—	—	—	44
Cumulative effect of accounting change	—	—	17	—
	$ 15,856	$ 10,799	$ 30,733	$ 19,534
Common unitholders				
Continuing operations	$ 24,160	$ 14,256	$ 41,614	$ 16,754
Discontinued operations	—	60	—	4,401
Cumulative effect of accounting change	—	—	1,340	—
	$ 24,160	$ 14,316	$ 42,954	$ 21,155
Series C unitholders				
Continuing operations	$ 5,383	$ —	$ 9,718	$ —
Cumulative effect of accounting change	—	—	333	—
	$ 5,383	$ —	$ 10,051	$ —
Basic earnings per common unit				
Income from continuing operations	$ 0.50	$ 0.33	$ 0.90	$ 0.40
Income from discontinued operations	—	—	—	0.11
Cumulative effect of accounting change	—	—	0.03	—
Net income	$ 0.50	$ 0.33	$ 0.93	$ 0.51
Diluted earnings per common unit				
Income from continuing operations	$ 0.50	$ 0.33	$ 0.90	$ 0.40
Income from discontinued operations	—	—	—	0.11
Cumulative effect of accounting change	—	—	0.03	—
Net income	$ 0.50	$ 0.33	$ 0.93	$ 0.51
Basic weighted average number of common units outstanding	48,005	42,842	46,024	41,297
Diluted weighted average number of common units outstanding	48,476	42,842	46,302	41,297
Distributions declared per common unit	$ 0.675	$ 0.650	$ 1.350	$ 1.275

See accompanying notes.

GULFTERRA ENERGY PARTNERS, L.P.

CONDENSED CONSOLIDATED BALANCE SHEETS
(In thousands, except unit amounts)
(Unaudited)

	June 30, 2003	December 31, 2002
ASSETS		
Current assets		
Cash and cash equivalents	$ 17,653	$ 36,099
Accounts receivable, net	200,891	223,345
Affiliated note receivable	17,100	17,100
Other current assets	5,524	3,451
Total current assets	241,168	279,995
Property, plant, and equipment, net	2,887,716	2,724,938
Intangible assets	3,489	3,970
Investment in unconsolidated affiliates	77,290	78,851
Other noncurrent assets	45,006	43,142
Total assets	$3,254,669	$3,130,896
LIABILITIES AND PARTNERS' CAPITAL		
Current liabilities		
Accounts payable	$ 194,782	$ 212,868
Accrued interest	13,590	15,028
Current maturities of senior secured term loan	5,000	5,000
Other current liabilities	13,857	21,195
Total current liabilities	227,229	254,091
Revolving credit facility	415,146	491,000
Senior secured term loans, less current maturities	312,500	552,500
Long-term debt	1,157,606	857,786
Other noncurrent liabilities	28,046	23,725
Total liabilities	2,140,527	2,179,102
Commitments and contingencies		
Minority interest	2,252	1,942
Partners' capital		
Limited partners		
Series B preference units; 124,014 and 125,392 units issued and outstanding	163,570	157,584
Common units; 49,786,921 and 44,030,314 units issued and outstanding	602,353	437,773
Series C units; 10,937,500 units issued and outstanding	346,792	351,507
General partner	10,240	8,610
Accumulated other comprehensive loss	(11,065)	(5,622)
Total partners' capital	1,111,890	949,852
Total liabilities and partners' capital	$3,254,669	$3,130,896

See accompanying notes.

GULFTERRA ENERGY PARTNERS, L.P.

CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
(In thousands)
(Unaudited)

	Six Months Ended June 30, 2003	Six Months Ended June 30, 2002
Cash flows from operating activities		
Net income	$ 91,512	$ 47,871
Less cumulative effect of accounting change	1,690	—
Less income from discontinued operations	—	4,445
Income from continuing operations	89,822	43,426
Adjustments to reconcile net income to net cash provided by operating activities		
Depreciation, depletion and amortization	48,543	30,665
Distributed earnings of unconsolidated affiliates		
Earnings from unconsolidated affiliates	(6,303)	(7,373)
Distributions from unconsolidated affiliates	8,230	9,180
(Gain) loss on sale of long-lived assets	257	(315)
Write-off of debt issuance costs	3,762	—
Other noncash items	4,520	1,495
Working capital changes, net of effects of acquisitions and noncash transactions	(14,665)	(20,514)
Net cash provided by continuing operations	134,166	56,564
Net cash provided by discontinued operations	—	5,037
Net cash provided by operating activities	134,166	61,601
Cash flows from investing activities		
Additions to property, plant and equipment	(207,011)	(91,318)
Proceeds from sale of assets	3,215	5,460
Additions to investments in unconsolidated affiliates	(197)	(14,144)
Cash paid for acquisitions, net of cash acquired	—	(730,166)
Net cash used in investing activities of continuing operations	(203,993)	(830,168)
Net cash provided by investing activities of discontinued operations	—	186,477
Net cash used in investing activities	(203,993)	(643,691)
Cash flows from financing activities		
Net proceeds from revolving credit facility	223,000	223,884
Repayments of revolving credit facility	(298,854)	(10,000)
Repayment of senior secured acquisition term loan	(237,500)	—
Net proceeds from GulfTerra Holding term credit facility	—	7,000
Net proceeds from GulfTerra Holding term loan	—	530,529
Repayment of senior secured term loan	(2,500)	(375,000)
Repayment of Argo term loan	—	(95,000)
Net proceeds from issuance of long-term debt	292,479	229,757
Net proceeds from issuance of common units and Series F convertible units	182,182	149,309
Distributions to partners	(107,427)	(73,214)
Contribution from General Partner	1	560
Net cash provided by financing activities of continuing operations	51,381	587,825
Net cash used in financing activities of discontinued operations	—	(4)
Net cash provided by financing activities	51,381	587,821
Increase (decrease) in cash and cash equivalents	(18,446)	5,731
Cash and cash equivalents		
Beginning of period	36,099	13,084
End of period	$ 17,653	$ 18,815
Schedule of noncash financing activities:		
Contribution from General Partner and redemption of Series B preference units	$ 1,788	$ —

See accompanying notes.

GULFTERRA ENERGY PARTNERS, L.P.

CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME AND CHANGES IN ACCUMULATED OTHER COMPREHENSIVE INCOME
(In thousands)
(Unaudited)

Comprehensive Income

	Quarter Ended June 30,		Six Months Ended June 30,	
	2003	2002	2003	2002
Net income	$49,297	$28,745	$91,512	$47,871
Other comprehensive income (loss)	272	(230)	(5,443)	1,171
Total comprehensive income	$49,569	$28,515	$86,069	$49,042

Accumulated Other Comprehensive Income (Loss)

	June 30, 2003	December 31, 2002
Beginning balance	$ (5,622)	$(1,272)
Unrealized mark-to-market losses on cash flow hedges arising during period	(11,026)	(6,428)
Reclassification adjustments for changes in initial value of derivative instruments to settlement date	5,751	1,579
Other comprehensive income (loss) from investment in unconsolidated affiliate	(168)	499
Ending balance	$(11,065)	$(5,622)
Accumulated other comprehensive loss allocated to:		
Common units' interest	$ (8,799)	$(4,623)
Series C units' interest	$ (2,155)	$ (942)
General partner's interests	$ (111)	$ (57)

See accompanying notes.

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS
(Unaudited)

1. BASIS OF PRESENTATION

In May 2003, we changed our name to GulfTerra Energy Partners, L.P. from El Paso Energy Partners, L.P. and reorganized our general partner. Our one percent general partner interest is now owned by GulfTerra Energy Company, L.L.C. replacing El Paso Energy Partners Company as the general partner. In connection with our name change, we have also changed the names of several subsidiaries including, but not limited to the following, as listed in the table below.

New Name	Former Name
GulfTerra Energy Finance Corporation	El Paso Energy Partners Finance Corporation
GulfTerra Arizona Gas, L.L.C.	El Paso Arizona Gas, L.L.C.
GulfTerra Intrastate, L.P.	El Paso Energy Intrastate, L.P.
GulfTerra Texas Pipeline, L.P.	EPGT Texas Pipeline, L.P.
GulfTerra Holding V, L.P.	EPN Holding Company, L.P.

We prepared this Quarterly Report on Form 10-Q under the rules and regulations of the United States Securities and Exchange Commission (SEC). Because this is an interim period filing presented using a condensed format, it does not include all of the disclosures required by generally accepted accounting principles. You should read it along with our 2002 Annual Report on Form 10-K, which includes a summary of our significant accounting policies and other disclosures. The financial statements as of June 30, 2003, and for the quarters and six months ended June 30, 2003 and 2002, are unaudited. We derived the balance sheet as of December 31, 2002, from the audited balance sheet filed in our 2002 Annual Report on Form 10-K. In our opinion, we have made all adjustments, all of which are of a normal, recurring nature, to fairly present our interim period results. Information for interim periods may not depict the results of operations for the entire year. In addition, prior period information presented in these financial statements includes reclassifications which were made to conform to the current period presentation. These reclassifications have no effect on our previously reported net income or partners' capital. We have also reflected the results of operations from our Prince assets disposition as discontinued operations in the quarter and six months ended June 30, 2002.

Our accounting policies are consistent with those discussed in our 2002 Annual Report on Form 10-K, except as discussed below.

Allowance for Doubtful Accounts

We have established an allowance for losses on accounts that we believe are uncollectible. Collectibility is reviewed regularly and the allowance is adjusted as necessary, primarily under the specific identification method. During the quarter ended June 30, 2003, we increased our allowance by $2.0 million. As of June 30, 2003 and December 31, 2002, our allowance was $4.5 million and $2.5 million.

As generally used in the energy industry and in this document, the following terms have the following meanings:

/d	= per day	Mcf	= thousand cubic feet
Bbl	= barrel	MDth	= thousand dekatherms
MBbls	= thousand barrels	MMcf	= million cubic feet
Bcf	= billion cubic feet	MMBbls	= million barrels

When we refer to cubic feet measurements, all measurements are at 14.73 pounds per square inch.

Accounting for Asset Retirement Obligations

On January 1, 2003, we adopted Statement of Financial Accounting Standards (SFAS) No. 143, *Accounting for Asset Retirement Obligations.* The provisions of this statement relate primarily to our obligations to plug abandoned offshore wells in our Garden Banks Blocks 72 and 117, Viosca Knoll Block 817, and West Delta Block 35.

Upon our adoption of SFAS No. 143, we recorded a $7.4 million net increase to property, plant, and equipment representing non-current retirement assets, a $5.7 million increase to noncurrent liabilities, representing retirement obligations, and a $1.7 million increase to income as a cumulative effect of accounting change. The retirement assets are depreciated over the remaining useful life of the long-term asset with which the retirement liability is associated. An ongoing expense is recognized for changes in the value of the retirement liability as a result of the passage of time, which we record as depreciation, depletion and amortization expense in our income statement.

Other than our obligations to plug and abandon wells, we cannot estimate the costs to retire or remove assets used in our business because we believe the assets do not have definite lives or we do not have the legal obligation to abandon or dismantle the assets. We believe that the life of our assets or the underlying reserves associated with our assets cannot be estimated. Therefore, aside from the liability associated with the plug and abandonment of offshore wells, we have not recorded liabilities relating to any of our other assets.

The pro forma income from continuing operations and amounts per unit for the quarter and six months ended June 30, 2003 and 2002, assuming asset retirement obligations as provided for in SFAS No. 143 were recorded prior to the earliest period presented, are shown below:

	Quarter Ended June 30,		Six Months Ended June 30,	
	2003	2002	2003	2002
	(In thousands, except per unit amounts)			
Pro forma income from continuing operations	$ 49,297	$ 28,583	$ 89,822	$ 43,250
Pro forma income from continuing operations allocated to common unitholders	$ 24,160	$ 14,155	$ 41,614	$ 16,580
Pro forma basic income from continuing operations per weighted average common unit	$ 0.50	$ 0.33	$ 0.90	$ 0.40
Pro forma diluted income from continuing operations per weighted average common unit	$ 0.50	$ 0.33	$ 0.90	$ 0.40

The pro forma amount of our asset retirement obligations at June 30, 2003 and 2002 and at December 31, 2002, assuming asset retirement obligations as provided for in SFAS No. 143 were recorded prior to the earliest period presented are shown below:

			Liability Balance as of	
Year	Liability Balance as of January 1	Accretion	June 30	December 31
	(In thousands)			
2002	$5,277	$224	$5,501	$5,726
2003	$5,726	$237	$5,963	N/A

Reporting Gains and Losses from the Early Extinguishment of Debt

In January 2003, we adopted SFAS No. 145, *Rescission of FASB Statements No. 4, 44, and 64, Amendment of FASB Statement No. 13, and Technical Corrections.* Accordingly, we now evaluate the nature of any debt extinguishments to determine whether to report any gain or loss resulting from the early extinguishment of debt as an extraordinary item or as income from continuing operations.

Accounting for Costs Associated with Exit or Disposal Activities

In January 2003, we adopted SFAS No. 146, *Accounting for Costs Associated with Exit or Disposal Activities.* This statement impacts any exit or disposal activities that we initiate after January 1, 2003 and we now recognize costs associated with exit or disposal activities when they are incurred rather than when we commit to an exit or disposal plan. Our adoption of this pronouncement did not have an effect on our financial position or results of operations.

Accounting for Guarantees

In accordance with the provisions of Financial Accounting Standards Board (FASB) Interpretation (FIN) No. 45, *Guarantor's Accounting and Disclosure Requirements for Guarantees, Including Indirect Guarantees of Indebtedness of Others,* we record a liability at fair value, or otherwise disclose, certain guarantees issued after December 31, 2002, that contractually require us to make payments to a guaranteed party based on the occurrence of certain events. We have not entered into any material guarantees that would require recognition under FIN No. 45.

Consolidation of Variable Interest Entities

In January 2003, the FASB issued FIN No. 46, *Consolidation of Variable Interest Entities, an Interpretation of ARB No. 51*. This interpretation defines a variable interest entity (VIE) as a legal entity whose equity owners do not have sufficient equity at risk and/or a controlling financial interest in the entity. This standard requires that companies consolidate a VIE if it is allocated a majority of the entity's losses and/or returns, including fees paid by the entity. We have not created nor have we obtained an interest in any VIEs since January 31, 2003, and therefore, our adoption of the initial provisions of this standard did not have an effect on our financial position or results of operations. Further, we have completed an assessment of our interests existing prior to February 1, 2003, and have determined that our adoption of the additional provisions of this standard will not have an effect on our financial position or results of operations.

Accounting for Stock-Based Compensation

We use the intrinsic value method established in Accounting Principles Board Opinion (APB) No. 25, *Accounting for Stock Issued to Employees*, to value unit options issued to former employees of our general partner and our current board of directors under our Omnibus Plan and Director Plan. For the quarters and six months ending June 30, 2003 and 2002, the cost of this stock-based compensation had no impact on our net income, as all options granted had an exercise price equal to the market value of the underlying common stock on the date of grant. We use the provisions of SFAS No. 123 to account for all of our other stock-based compensation programs.

In December 2002, the FASB issued SFAS No. 148, *Accounting for Stock-Based Compensation Transition and Disclosure*. This statement amends SFAS No. 123, to provide alternative methods of transition for a voluntary change to the fair value method of accounting for stock-based employee compensation. In addition, this statement amends the disclosure requirements of SFAS No. 123 to require prominent disclosures in both annual and interim financial statements about the methods of accounting for stock-based employee compensation for former employees of our general partner and our board of directors, and the effect of the method used on reported results. This statement is effective for the fiscal years ending after December 15, 2002. We have decided that we will continue to use APB No. 25 to value our stock-based compensation issued to our former employees and our board of directors and will include data providing the pro forma income impacts of using the fair value method as required by SFAS No. 148. We will continue to use the provisions of SFAS No. 123 to account for all of our other stock based compensation programs.

If compensation expense related to these plans had been determined by applying the fair value method in SFAS No. 123, *Accounting for Stock-Based Compensation*, our net income allocated to common unitholders and net income per common unit would have approximated the pro forma amounts below:

	Quarter Ended June 30,		Six Months Ended June 30,	
	2003	2002	2003	2002
	(In thousands)			
Net income allocated to common unitholders, as reported	$24,160	$14,316	$42,954	$21,155
Add: Stock-based employee compensation expense included in reported net income	366	270	679	540
Less: Stock-based employee compensation expense determined under fair value based method	406	609	720	1,182
Pro forma net income allocated to common unitholders	$24,120	$13,977	$42,913	$20,513
Earnings per common unit:				
Basic, as reported	$ 0.50	$ 0.33	$ 0.93	$ 0.51
Basic, pro forma	$ 0.50	$ 0.33	$ 0.93	$ 0.50
Diluted, as reported	$ 0.50	$ 0.33	$ 0.93	$ 0.51
Diluted, pro forma	$ 0.50	$ 0.33	$ 0.93	$ 0.50

The effects of applying SFAS No. 123 in this pro forma disclosure may not be indicative of pro forma future amounts.

2. ACQUISITION

During the six months ended June 30, 2003, the total purchase price and net assets acquired for the April 2002 EPN Holding asset acquisition increased $17.5 million due to post-closing purchase price adjustments related primarily to natural gas imbalances assumed in the transaction. The following table summarizes our allocation of the fair values of the assets acquired and liabilities assumed. Our allocation among the assets acquired is based on the results of an independent third-party appraisal.

	At April 8, 2002
	(In thousands)
Current assets	$ 4,690
Property, plant and equipment	780,648
Intangible assets	3,500
Total assets acquired	788,838
Current liabilities	15,229
Environmental liabilities	21,136
Total liabilities assumed	36,365
Net assets acquired	$752,473

3. PARTNERS' CAPITAL

Cash distributions

The following table reflects our per unit cash distributions to our common unitholders and the total distributions paid to our common unitholders, Series C unitholder and general partner during the six months ended June 30, 2003:

Month paid	Common Unit	Common Unitholders	Series C Unitholder	General Partner
	(per unit)	(In millions)		
February	$0.675	$29.7	$7.4	$15.0
May	$0.675	$32.0	$7.4	$15.9

In July 2003 we declared a cash distribution of $0.70 per common unit and Series C unit, $42.5 million in aggregate, for the quarter ended June 30, 2003, which we will pay on August 15, 2003, to holders of record as of July 31, 2003. Also in August 2003, we will pay our general partner $18.0 million related to its general partner interest. At the current distribution rates, our general partner receives approximately 29.8 percent of the total cash distributions for its role as our general partner.

Public offering of common units

In June 2003, we issued 1,150,000 common units at the public offering price of $36.50 per unit and in April 2003, we issued 3,450,000 common units at the public offering price of $31.35 per unit. We used the net cash proceeds of approximately $40.3 million and $103.1 million to temporarily reduce indebtedness outstanding under our $600 million revolving credit facility and pay fees and expenses associated with these offerings.

In May 2003, we issued 1,118,881 common units and 80 Series F convertible units in a registered offering to an institutional investor for approximately $38.3 million net of offering costs. Our Series F convertible units are not listed on any securities exchange or market. Each Series F convertible unit is comprised of two separate detachable units — a Series F1 convertible unit and a Series F2 convertible unit — that have identical terms except for vesting and termination dates and the number of underlying common units into which they may be converted. The Series F1 units are convertible into up to $80 million of common units anytime after August 12, 2003, and until March 29, 2004 (subject to defined extension rights). The Series F2 units are convertible into up to $40 million of common units provided at least $40 million of Series F1 convertible units are converted prior to their termination. The Series F2 units terminate on March 30, 2005 (subject to defined extension rights). The price at which the Series F convertible units may be converted to common units is equal to the lesser of the prevailing price (as defined below), if the prevailing price is equal to or greater than $35.75 or the prevailing price minus the product of 50 percent of the positive difference, if any, of $35.75 minus the prevailing price. The prevailing price is equal to the lesser of (i) the average closing price of our common units for the 60 business days ending on and including the fourth business day prior to our receiving notice from the holder of the Series F convertible units of their intent to convert them into common units; (ii) the average closing price of our common units for the first seven business days of the 60 day period included in (i); or (iii) the average closing price of our common units for the last seven days of the 60 day period included in (i). If they had been eligible for conversion, the price at which the Series F convertible units could have been converted to common units, based on the previous 60 business days at June 30, 2003 and August 7, 2003, was $29.67 and $36.15. The Series F convertible units may be converted into a maximum of 8,329,679 common units and are not entitled to any distributions, nor do they have any voting rights, prior to conversion. The value associated with the Series F convertible units is included in partners' capital as a component of common units.

The Series F convertible units have a feature which allows us to establish a minimum conversion unit price. Should the actual conversion unit price be below the minimum conversion unit price, we would be required to settle the conversion in cash in lieu of issuing common units. Currently, no minimum conversion unit price has been established; however, if a minimum conversion unit price is established, we may have to change our accounting treatment for the Series F convertible units to account for them as a derivative under the provisions of SFAS No. 133 and record an asset or liability for the fair value of the Series F convertible units, and the changes in fair value would impact our earnings.

In connection with these offerings, our general partner, in lieu of a cash contribution, redeemed approximately $1.8 million of our Series B preference units in order to maintain its one percent general partner interest, and these preference units were subsequently retired.

Other

Under the 1998 Omnibus Compensation Plan (Omnibus Plan), we granted, during the quarter ended June 30, 2003, 17,500 unit options, 15,000 time-vested restricted units and 15,000 performance-based restricted units to employees of El Paso Field Services. Additionally, 5,226 restricted units and 10,500 unit options were granted during the quarter ended June 30, 2003, to non-employee directors of our Board of Directors under the 1998 Unit Option Plan for Non-Employee Directors. We have accounted for the unit options and restricted units issued under the Omnibus Plan and the restricted units issued to non-employee directors of our Board of Directors in accordance with SFAS No. 123. Under SFAS No. 123, the fair value of these issuances is reflected as deferred compensation. Deferred compensation is amortized to compensation expense over the respective vesting or performance period. The unit options issued to the non-employee directors of our Board of Directors have been accounted for in accordance with APB No. 25.

The fair value of each unit option issued under the Omnibus Plan during the quarter ended June 30, 2003, is estimated on the date of grant using the Black-Scholes option-pricing model with the following weighted average assumptions: dividend yield of 8.75%; expected volatility of 30.77%; risk-free interest rates of 3.31%; and expected lives of eight years. The fair value of the unit options will be amortized over the two year vesting period.

The time-vested restricted units and the performance-based restricted units were granted at a fair value of $36.69 per unit. The restrictions on the time-vested units will lapse in four years from the date of grant and restrictions on the performance-based restricted units will lapse upon us achieving a specified level of target performance for identified greenfield projects by June 1, 2007. If the target is not reached by June 1, 2007, the units will be forfeited. The fair value of the time-vested restricted units is being amortized over the four-year restricted period and the fair value of the performance-based restricted units is being amortized over the performance period. The performance-based restricted units are not entitled to any distributions, nor do they have any voting rights, prior to the specified level of target performance being achieved. The restricted units issued to non-employee directors of our Board of Directors were issued at a fair value of $36.35 per unit. This fair value is being amortized to compensation expense over the period of service, which we have estimated to be one year.

Total unamortized deferred compensation as of June 30, 2003, was approximately $1.7 million. Deferred compensation is reflected as a reduction of partners' capital and is allocated 1% to our general partner and 99% to our limited partners.

4. EARNINGS PER COMMON UNIT

The following table sets forth the computation of basic and diluted earnings per common unit (in thousands):

	Quarter Ended		Six Months Ended	
	June 30, 2003	June 30, 2002	June 30, 2003	June 30, 2002
Numerator:				
Numerator for basic earnings per common unit —				
Income from continuing operations	$24,160	$14,256	$41,614	$16,754
Income from discontinued operations	—	60	—	4,401
Cumulative effect of accounting change	—	—	1,340	—
	$24,160	$14,316	$42,954	$21,155
Denominator:				
Denominator for basic earnings per common unit — weighted-average shares	48,005	42,842	46,024	41,297
Effect of dilutive securities:				
Unit options	146	—	112	—
Restricted units	9	—	8	—
Series F convertible units	316	—	158	—
Denominator for diluted earnings per common unit — adjusted for weighted-average common units	48,476	42,842	46,302	41,297
Basic earnings per common unit				
Income from continuing operations	$ 0.50	$ 0.33	$ 0.90	$ 0.40
Income from discontinued operations	—	—	—	0.11
Cumulative effect of accounting change	—	—	0.03	—
	$ 0.50	$ 0.33	$ 0.93	$ 0.51
Diluted earnings per common unit				
Income from continuing operations	$ 0.50	$ 0.33	$ 0.90	$ 0.40
Income from discontinued operations	—	—	—	0.11
Cumulative effect of accounting change	—	—	0.03	—
	$ 0.50	$ 0.33	$ 0.93	$ 0.51

5. PROPERTY, PLANT AND EQUIPMENT

Our property, plant and equipment consisted of the following:

	June 30, 2003	December 31, 2002
	(In thousands)	
Property, plant and equipment, at cost		
Pipelines	$2,339,568	$2,317,503
Platforms and facilities	121,105	120,962
Processing plant	309,057	308,517
Oil and natural gas properties	131,100	127,975
Storage facilities	333,349	331,562
Construction work-in-progress	363,726	177,964
	3,597,905	3,384,483
Less accumulated depreciation, depletion and amortization	710,189	659,545
Property, plant and equipment, net	$2,887,716	$2,724,938

6. FINANCING TRANSACTIONS

Credit Facilities

Our credit facility consists of two parts: a $600 million revolving credit facility maturing in May 2004 and a $160 million senior secured term loan maturing in 2007. Our credit facility and the GulfTerra Holding V, L.P. (GulfTerra Holding) term credit facility are guaranteed by us and all of our subsidiaries, except for our unrestricted subsidiaries, as detailed in Note 12, and by GulfTerra Energy Finance Corporation and our general partner, and are collateralized with substantially all of our assets (excluding the assets of our unrestricted subsidiaries) and our general partner's general and administrative services agreement. The interest rates we are charged on each of these credit facilities are determined using one of two indices that include (i) a variable base rate (equal to the greater of the prime rate as determined by JPMorgan Chase Bank, the federal funds rate plus 0.5% or the Certificate of Deposit (CD) rate as determined by JPMorgan Chase Bank increased by 1.00%); or (ii) LIBOR.

Our revolving credit facility, senior secured term loan and the GulfTerra Holding term credit facility contain covenants that include restrictions on our and our subsidiaries' ability to incur additional indebtedness or liens, sell assets, make loans or investments, acquire or be acquired by other companies and amend some of our contracts, as well as requiring maintenance of certain financial ratios. Failure to comply with the provisions of any of these covenants could result in acceleration of our debt and other financial obligations and that of our subsidiaries and restrict our ability to make distributions to our unitholders.

Revolving Credit Facility

As of June 30, 2003, we had $415 million outstanding on our revolving credit facility at an average interest rate of 3.43%. The total amount available to us at June 30, 2003 under this facility was $155 million. The amounts outstanding under this facility bear interest at our option at either (i) 0.75% over the variable base rate described above; or (ii) 1.75% over LIBOR. We are currently negotiating the renewal of our revolving credit facility to extend the maturity date beyond May 2004 on terms not more restrictive than our existing facility. We intend and believe we have the ability to renew this facility and have continued to classify the facility as long-term debt in our balance sheet as of June 30, 2003.

Senior Secured Term Loan

As of June 30, 2003, we had $157.5 million outstanding under our senior secured term loan with an average interest rate of 4.75%. The amounts outstanding under this senior secured term loan bear interest at our option at either (i) 2.25% over the variable base rate described above; or (ii) 3.50% over LIBOR.

GulfTerra Holding Term Credit Facility

As of June 30, 2003, the outstanding balance under the GulfTerra Holding term credit facility was $160 million with an average interest rate of 3.60%. The balance outstanding under the GulfTerra Holding term credit facility bears interest at our option at either (i) 1.00% over the variable base rate described above; or (ii) 2.25% over LIBOR. We repaid this term credit facility in July 2003 with proceeds from our issuance of $250 million 6¼% senior notes due 2010.

Senior Secured Acquisition Term Loan

As part of our November 2002 San Juan assets acquisition, we entered into a $237.5 million senior secured acquisition term loan to fund a portion of the purchase price. We repaid the senior secured acquisition term loan in March 2003 with proceeds from our issuance of $300 million 8½% senior subordinated notes due 2010. We recognized a loss of $3.8 million related to the write-off of unamortized debt issuance costs. From the issuance of the senior secured acquisition term loan in November 2002 to its repayment date, the interest rates on our revolving credit facility and GulfTerra Holding term credit facility were 2.25% over the variable base rate described above or LIBOR increased by 3.50%.

Senior Notes

In July 2003, we issued $250 million in aggregate principal amount of 6¼% senior notes due June 2010, a new class of debt for us. The interest on our senior notes is payable semi-annually in June and December with the principal maturing in June 2010. Our senior notes are unsecured obligations that rank equally with all of our existing and future senior debt, senior to all our existing and future subordinated debt and junior in right of payment to all of our existing and future senior secured debt.

We may redeem some or all of our senior notes, at our option, at any time with at least 30 days notice at a price equal to the greater of (i) 100 percent of the principal amount plus accrued interest, or (ii) the sum of the present value of the remaining scheduled payments plus accrued interest. Our senior notes are subject to a registration rights agreement under which we are required to file an exchange offer registration statement with the SEC on or prior to October 6, 2003. The registration statement must then become effective on or prior to December 1, 2003 or we will be subject to additional interest until the registration statement is declared effective. We used the proceeds of approximately $245.1 million, net of issuance costs, to repay $160 million of indebtedness under the GulfTerra Holding term credit facility and to temporarily repay $85.1 million of the balance outstanding under our revolving credit facility.

Senior Subordinated Notes

Each issue of our senior subordinated notes is subordinated in right of payment to all existing and future senior debt including our existing credit facilities and the senior notes we issued in July 2003.

In March 2003, we issued $300 million in aggregate principal amount of 8½% senior subordinated notes. The interest on these notes is payable semi-annually in June and December, and the notes mature in June 2010. We used the proceeds of approximately $293 million, net of issuance costs, to repay $237.5 million of indebtedness under our senior secured acquisition term loan and to temporarily repay $55.5 million of the balance outstanding under our revolving credit facility. In June 2003, we filed an exchange offer registration statement with the SEC which became effective July 19, 2003. We may, at our option, prior to June 1, 2006, redeem up to 33 percent of the originally issued aggregate principal amount of these notes at a redemption price of 108.50 percent of the principal amount. On or after June 1, 2007, we may redeem all or part of these notes at 104.25 percent of the principal amount.

In July 2003, to achieve a better mix of fixed rate debt and variable rate debt, we entered into an eight-year interest rate swap agreement to provide for a floating interest rate on our fixed 8½% $250 million senior subordinated notes that were issued in May 2001. With this swap agreement, we will pay the counterparty a LIBOR based interest rate plus a spread of 4.20% and receive a fixed rate of 8½%. We are accounting for this derivative as a fair value hedge.

Restrictive Provisions of Senior and Senior Subordinated Notes

Our senior and senior subordinated notes include provisions that, among other things, restrict our ability and the ability of our subsidiaries (excluding our unrestricted subsidiaries) to incur additional indebtedness or liens, sell assets, make loans or investments, acquire or be acquired by other companies, and enter into sale and lease-back transactions, as well as requiring maintenance of certain financial ratios. Failure to comply with the provisions of these covenants could result in acceleration of our debt and other financial obligations and that of our subsidiaries in addition to restricting our ability to make distributions to our unitholders. Many restrictive covenants associated with our senior notes will effectively be removed following a period of 90 consecutive days during which they are rated Baa3 or higher by Moody's or BBB− or higher by S&P, and some of the more restrictive covenants associated with certain of our senior subordinated notes will be suspended should they be similarly rated.

Other Credit Facilities

Poseidon

Poseidon Oil Pipeline Company, L.L.C., an unconsolidated affiliate in which we have a 36 percent joint venture ownership interest, is party to a $185 million credit agreement, under which it has $125 million outstanding at June 30, 2003, that may restrict its ability to pay distributions to its owners. Beginning in April 2003, the additional interest Poseidon pays over LIBOR was reduced from 1.50% to 1.25% as a result of improvement in Poseidon's debt ratio, as defined in its credit agreement.

In January 2002, Poseidon entered into a two-year interest rate swap agreement to fix the variable portion of its LIBOR based interest rate on $75 million of the $125 million outstanding under its credit facility at 3.49% through January 2004. The effective fixed interest rate on the hedged notional amount currently is 4.74% (the variable LIBOR based rate of 3.49% plus the margin of 1.25%). As of June 30, 2003, the remaining $50 million was at an average interest rate of 2.49%.

Deepwater Gateway

As of June 30, 2003, Deepwater Gateway, an unconsolidated affiliate in which we have a 50 percent joint venture ownership interest, had $109 million outstanding under its construction loan at an average interest rate of 3.02%. This construction loan will mature in July 2004 unless construction is completed before that time and Deepwater Gateway meets other specified conditions, in which case the construction loan will convert into a term loan with a final maturity date of July 2009. Upon conversion of the construction loan to a term loan, Deepwater Gateway will be required to maintain a debt service reserve equal to or greater than the projected principal, interest and fees due on the term loan for the immediately succeeding six month period. Prior to conversion to the term loan Deepwater Gateway is prohibited from making distributions.

Cameron Highway

Cameron Highway Oil Pipeline Company (Cameron Highway), an unconsolidated affiliate in which we have a 50 percent joint venture ownership interest (See Note 10 for additional discussion relating to the formation of Cameron Highway), entered into a $325 million project loan facility, consisting of a $225 million construction loan and $100 million of senior secured notes.

The $225 million construction loan bears interest at Cameron Highway's option at each borrowing at either (i) 2.00% over the variable base rate (equal to the greater of the prime rate as determined by JPMorgan Chase Bank, the federal funds rate plus 0.5% or the Certificate of Deposit (CD) rate as determined by JPMorgan Chase Bank increased by 1.00%); or (ii) 3.00% over LIBOR. Upon completion of the construction, the construction loan will convert to a term loan maturing July 2008, subject to the terms of the loan agreement. At the end of the first quarter following the first anniversary of the conversion into a term loan, Cameron Highway will be required to make quarterly payments of $8.125 million, with the remaining unpaid principal amount payable on the maturity date. If the construction loan fails to convert into a term loan by December 31, 2006, the construction loan and senior secured notes become fully due and payable.

The interest rate on the notes will be at the 10-year U.S. Treasury security rate plus 3.25%. Principal and interest payments of $4 million will be due quarterly from September 2008 through December 2011, $6 million each from March 2012 through December 2012, and $5 million each from March 2013 through the principal maturity date of December 2013.

Under the terms of the project loan facility, Cameron Highway must pay each of the lenders and the senior secured note holders commitment fees of 0.5% per annum on any unused portion of such lender's or noteholder's committed funds. The project loan facility as a whole is collateralized by (i) substantially all of Cameron Highway's assets, including, upon conversion, a debt service reserve capital account, and (ii) all of the equity interest in Cameron Highway. Other than the pledge of our equity interest and our construction obligations under the relevant producer agreements, as discussed in Note 10, the debt is non-recourse to us. The construction loan and senior secured notes prohibit Cameron Highway from making distributions to us until the construction loan is converted into a term loan and Cameron Highway meets certain financial requirements.

Debt Maturity Table

Aggregate maturities of the principal amounts of long-term debt and other financing obligations for the next 5 years and in total thereafter are as follows at June 30, 2003 (in thousands):

2003	$ 2,500
2004[1]	420,146
2005	165,000
2006	5,000
2007	140,000
Thereafter	1,155,000
Total long-term debt and other financing obligations, including current maturities	$1,887,646

[1] Balance includes our revolving credit facility; however, we are negotiating the renewal to extend the maturity date beyond May 2004. We intend and believe we have the ability to renew this facility and have continued to classify the facility as long-term debt on our balance sheet as of June 30, 2003.

7. COMMITMENTS AND CONTINGENCIES

Legal Proceedings

Grynberg. In 1997, we were named defendants in actions brought by Jack Grynberg on behalf of the U.S. Government under the False Claims Act. Generally, these complaints allege an industry-wide conspiracy to underreport the heating value as well as the volumes of the natural gas produced from federal and Native American lands, which deprived the U.S. Government of royalties. The plaintiff in this case seeks royalties that he contends the government should have received had the volume and heating value of natural gas produced from royalty properties been differently measured, analyzed, calculated and reported, together with interest, treble damages, civil penalties, expenses and future injunctive relief to require the defendants to adopt allegedly appropriate gas measurement practices. No monetary relief has been specified in this case. These matters have been consolidated for pretrial purposes (In re: Natural Gas Royalties *Qui Tam* Litigation, U.S. District Court for the District of Wyoming, filed June 1997). In May 2001, the court denied the defendants' motions to dismiss. Discovery is proceeding. Our costs and legal exposure related to these lawsuits and claims are not currently determinable.

Will Price (formerly Quinque). We have also been named defendants in *Quinque Operating Company, et al v. Gas Pipelines and Their Predecessors, et al,* filed in 1999 in the District Court of Stevens County, Kansas. Quinque has been dropped as a plaintiff and Will Price has been added. This class action complaint alleges that the defendants mismeasured natural gas volumes and heating content of natural gas on non-federal and non-Native American lands. The plaintiffs in this case seek certification of a nationwide class of natural gas working interest owners and natural gas royalty owners to recover royalties that the plaintiffs contend these owners should have received had the volume and heating value of natural gas produced from their properties been differently measured, analyzed, calculated and reported, together with prejudgment and postjudgment interest, punitive damages, treble damages, attorney's fees, costs and expenses, and future injunctive relief to require the defendants to adopt allegedly appropriate gas measurement practices. No monetary relief has been specified in this case. Plaintiffs' motion for class certification was denied in April 2003. Plaintiffs filed another amended petition to narrow the proposed class to royalty owners in Kansas, Wyoming and Colorado and their motion was granted on July 28, 2003. Our costs and legal exposure related to this lawsuit and claims are not currently determinable.

In connection with our April 2002 acquisition of the EPN Holding assets, subsidiaries of El Paso Corporation have agreed to indemnify us against all obligations related to existing legal matters at the acquisition date, including the legal matters involving Leapartners, L.P., City of Edinburg, Houston Pipe Line Company LP, and City of Corpus Christi discussed below.

During 2000, Leapartners, L.P. filed a suit against El Paso Field Services and others in the District Court of Loving County, Texas, alleging a breach of contract to gather and process natural gas in areas of western Texas related to an asset now owned by GulfTerra Holding. In May 2001, the court ruled in favor of Leapartners and entered a judgment against El Paso Field Services of approximately $10 million. El Paso Field Services has filed an appeal with the Eighth Court of Appeals in El Paso, Texas. Briefs have been filed and oral arguments were heard in November 2002. Review by the Court of Appeals is expected in the third quarter of 2003.

Also, GulfTerra Texas Pipeline L.P., (GulfTerra Texas, formerly known as EPGT Texas Pipeline L.P.) now owned by GulfTerra Holding, is involved in litigation with the City of Edinburg concerning the City's claim that GulfTerra Texas was required to pay pipeline franchise fees under a contract the City had with Rio Grande Valley Gas Company, which was previously owned by GulfTerra Texas and is now owned by Southern Union Gas Company. An adverse judgment against Southern Union and GulfTerra Texas was rendered in Hidalgo County State District court in December 1998 and found a breach of contract, and held both GulfTerra Texas and Southern Union jointly and severally liable to the City for approximately $4.7 million. The judgment relies on the single business enterprise doctrine to impose contractual obligations on GulfTerra Texas and Southern Union's entities that were not parties to the contract with the City. GulfTerra Texas has appealed this case to the Texas Supreme Court seeking reversal of the judgment rendered against GulfTerra Texas. The City seeks a remand to the trial court of its claim of tortious interference against GulfTerra Texas. Briefs have been filed and oral arguments were held in November 2002, and we are awaiting a decision.

In December 2000, a 30-inch natural gas pipeline jointly owned by GulfTerra Intrastate, L.P. (GulfTerra Intrastate) now owned by GulfTerra Holding, and Houston Pipe Line Company LP ruptured in Mont Belvieu, Texas, near Baytown, resulting in substantial property damage and minor physical injury. GulfTerra Intrastate is the operator of the pipeline. Two lawsuits were filed in the state district court in Chambers County, Texas by eight plaintiffs, including two homeowners' insurers. The suits seek recovery for physical pain and suffering, mental anguish, physical impairment, medical expenses, and property damage. Houston Pipe Line Company has been added as an additional defendant. In accordance with the terms of the operating agreement, GulfTerra Intrastate has agreed to assume the defense of and to indemnify Houston Pipe Line Company. As of June 30, 2003, all but one claim has now been settled and these settlements had no impact on our financial statements. The remaining claim relates solely to property damages.

The City of Corpus Christi, Texas (the "City") is alleging that GulfTerra Texas and various Coastal entities owe it monies for past obligations under City ordinances that propose to tax GulfTerra Texas on its gross receipts from local natural gas sales for the use of street rights-of-way. No lawsuit has been filed to date. Some but not all of the GulfTerra Texas pipe at issue has been using the rights-of-way since the 1960's. In addition, the City demands that GulfTerra Texas agree to a going-forward consent agreement in order for the GulfTerra Texas pipe and Coastal pipe to have the right to remain in City rights-of-way.

In August 2002, we acquired the Big Thicket assets, which consist of the Vidor plant, the Silsbee compressor station and the Big Thicket gathering system located in east Texas, for approximately $11 million from BP America Production Company (BP). Pursuant to the purchase agreement, we have identified environmental conditions that we are working with BP and appropriate regulatory agencies to address. BP has agreed to indemnify us for exposure resulting from activities related to the ownership or operation of these facilities prior to our purchase (i) for a period of three years for non-environmental claims and (ii) until one year following the completion of any environmental remediation for environmental claims. Following expiration of these indemnity periods, we are obligated to indemnify BP for environmental or non-environmental claims. We, along with BP and various other defendants, have been named in the following two lawsuits for claims based on activities occuring prior to our purchase of these facilities.

Christopher Beverly and Gretchen Beverly, individually and on behalf of the estate of John Beverly v. GulfTerra GC, L.P., et, al. In June 2003, the plaintiffs in this recently filed court action sued us in state district court in Hardin County, Texas. The plaintiffs are the parents of John Christopher Beverly, a two year old child who died on April 15, 2002, allegedly as the result of his exposure to arsenic, benzene and other harmful chemicals in the water supply. Plaintiffs allege that several defendants are responsible for that contamination, including us and BP. Our connection to the occurrences that are the basis for this suit appears to be our August 2002 purchase of certain assets from BP, including a facility in Hardin County, Texas known as the Silsbee compressor station. Under the terms of the indemnity provisions in the Purchase and Sale Agreement between GulfTerra and BP, GulfTerra requested that BP indemnify GulfTerra for any exposure. BP has thus far declined assuming the indemnity obligation. Our costs and legal exposure related to this lawsuit and claims are not currently determinable.

Melissa Duvail, et. al., v. GulfTerra GC, L.P., et. al. In June 2003, seventy-four residents of Hardin County, Texas, sued us and others in state district court in Hardin County, Texas. The plaintiffs allege that they have been exposed to hazardous chemicals, including arsenic and benzene, through their water supply, and that the defendants are responsible for that exposure. As with the Beverly case, our connection with the occurrences that are the basis of this suit appears to be our August 2002 purchase of certain assets from BP, including a facility known as the Silsbee compressor station, which is located in Hardin County, Texas. Under the terms of the indemnity provisions in the Purchase and Sale Agreement between us and BP, BP has agreed to indemnify us for this matter.

In addition to the above matters, we and our subsidiaries and affiliates are named defendants in numerous lawsuits and governmental proceedings that arise in the ordinary course of our business.

For each of our outstanding legal matters, we evaluate the merits of the case, our exposure to the matter, possible legal or settlement strategies and the likelihood of an unfavorable outcome. If we determine that an unfavorable outcome is probable and can be estimated, we will establish the necessary accruals. As of June 30, 2003, we had no reserves for our legal matters.

While the outcome of our outstanding legal matters cannot be predicted with certainty, based on information known to date, we do not expect the ultimate resolution of these matters will have a material adverse effect on our financial position, results of operations or cash flows. As new information becomes available or relevant developments occur, we will establish accruals as appropriate.

Environmental

Each of our operating segments is subject to extensive federal, state, and local laws and regulations governing environmental quality and pollution control. These laws and regulations are applicable to each segment and require us to remove or remedy the effect on the environment of the disposal or release of specified substances at current and former operating sites. As of June 30, 2003, we had a reserve of approximately $21 million for remediation costs expected to be incurred over time associated with mercury meters. We assumed this liability in connection with our April 2002 acquisition of the EPN Holding assets. As part of the November 2002 San Juan assets acquisition, El Paso Corporation has agreed to indemnify us for all the known and unknown environmental liabilities related to the assets we purchased up to the purchase price of $766 million. We will only be indemnified for unknown liabilities for up to three years from the purchase date of this acquisition. In addition, we have been indemnified by third parties for remediation costs associated with other assets we have purchased. We expect to make capital expenditures for environmental matters of approximately $10 million in the aggregate for the years 2003 through 2007, primarily to comply with clean air regulations.

While the outcome of our outstanding environmental matters cannot be predicted with certainty, based on the information known to date and our existing accruals, we do not expect the ultimate resolution of these matters will have a material adverse effect on our financial position, results of operations or cash flows. It is possible that new information or future developments could require us to reassess our potential exposure related to environmental matters. We may incur significant costs and liabilities in order to comply with existing environmental laws and regulations. It is also possible that other developments, such as increasingly strict environmental laws and regulations and claims for damages to property, employees, other persons and the environment resulting from our current or past operations, could result in substantial costs and liabilities in the future. As this information becomes available, or relevant developments occur, we will adjust our accrual amounts accordingly. While there are still uncertainties relating to the ultimate costs we may incur, based upon our evaluation and experience to date, we believe our current reserves are adequate.

Rates and Regulatory Matters

Marketing Affiliate Notice of Proposed Rulemaking. In September 2001, the Federal Energy Regulatory Commission (FERC) issued a Notice of Proposed Rulemaking (NOPR). The NOPR proposes to apply the standards of conduct governing the relationship between interstate pipelines and marketing affiliates to all energy affiliates. Since our High Island Offshore System (HIOS) and Petal Gas Storage facility, including the 59-mile Petal gas pipeline, are interstate facilities as defined by the Natural Gas Act, the proposed regulations, if adopted by FERC, would dictate how HIOS and Petal conduct business and interact with all of our energy affiliates and El Paso Corporation's energy affiliates. In December 2001, we filed comments with the FERC addressing our concerns with the proposed rules. A public conference was held in May 2002, providing an opportunity to comment further on the NOPR. Following the conference, we filed additional comments. At this time, we cannot predict the outcome of the NOPR, but adoption of the regulations in the form proposed would, at a minimum, place additional administrative and operational burdens on us.

If the standards of conduct NOPR is adopted by the FERC, we will be required to functionally separate our HIOS and Petal interstate facilities from our other businesses. Under the proposed rule, we would be required to dedicate employees to manage and operate our interstate facilities independently from our other non-jurisdictional facilities. This employee group would be required to function independently and would be prohibited from communicating non-public transportation information to affiliates. Separate office facilities and systems would be necessary because of the requirement to restrict affiliate access to interstate transportation information. The NOPR also limits the sharing of employees and officers with non-regulated entities. Because of the loss of synergies and shared employee restrictions, a disposition of the interstate facilities may be necessary for us to effectively comply with the rule. At this time, we cannot predict the outcome of this NOPR.

Negotiated Rate Policy. In July 2002, the FERC issued a Notice of Inquiry (NOI) that sought comments regarding its 1996 policy of permitting pipelines to enter into negotiated rate transactions. On July 25, 2003, the FERC issued modifications to its negotiated rate policy applicable to interstate natural gas pipelines. The new policy has two primary changes. First, the FERC will no longer permit the pricing of negotiated rates based on natural gas commodity price indices, although it will permit current contracts negotiated on that basis to continue until the end of the applicable contract period. Second, the FERC is imposing new filing requirements on pipelines to ensure the transparency of negotiated rate transactions.

Interim Rule on Cash Management. In August 2002, the FERC issued a NOPR proposing that all cash management or money pool arrangements between a FERC-regulated subsidiary and its non-FERC regulated parent must be in writing and that, as a condition of participating in a cash management or money pool arrangement, the FERC-regulated entity maintain a minimum proprietary capital balance of 30 percent and both it and its parent maintain investment grade credit ratings. After receiving written comments and hearing industry participant's concerns at a public conference in September 2002, the FERC issued an Interim Rule on Cash Management in June 2003, which did not adopt the proposed limitations on entry into or participation in cash management programs. Instead, the Interim Rule requires natural gas companies to maintain up-to-date documentation authorizing the establishment of the cash management program in which they participate and supporting all deposits into, borrowings from, interest income from, and interest expense to such program.

The Interim Rule seeks comments on a proposed requirement that mandates FERC-regulated entities to file the cash management agreements with the FERC and changes to the agreement within ten days and notify the FERC within 5 days when its proprietary capital ratio falls below 30 percent (or conversely, its long-term debt rises above 70 percent) and when it subsequently returns to or exceeds 30 percent. We filed comments on the Interim Rule on August 7, 2003. Under these interim rules we believe that both HIOS and Petal will be able to continue to participate in our cash management program.

Emergency Reconstruction of Interstate Natural Gas Facilities Final Rule. On May 19, 2003, the FERC issued a Final Rule that amends its regulations to enable natural gas interstate pipeline companies, in emergency situations resulting in sudden unanticipated loss of natural gas or capacity, to replace facilities when immediate action is required for the protection of life or health or for the maintenance of physical property. Specifically, the Final Rule permits a pipeline to replace mainline facilities using a route other than an existing right-of-way, to commence construction without being subject to a 45-day waiting period, and to undertake projects that exceed the existing blanket cost constraints. Lastly, the Final Rule requires that landowners be notified of potential construction but provides for a possible waiver of the 30-day waiting period.

Pipeline Safety Notice of Proposed Rulemaking. In January 2003, the U.S. Department of Transportation issued a NOPR proposing to establish a rule requiring pipeline operators to develop integrity management programs to comprehensively evaluate their pipelines, and take measures to protect pipeline segments located in what the notice refers to as "high consequence areas." The proposed rule resulted from the enactment of the Pipeline Safety Improvement Act of 2002, a new bill signed into law in December 2002. Comments on the NOPR were filed on April 30, 2003. At this time, we cannot predict the outcome of this NOPR.

Financial Reporting Notice of Proposed Rulemaking. In June 2003, the FERC issued a NOPR that proposes to establish quarterly financial reporting requirements, which are similar to the current Annual Report but will require the addition of Management's Discussion and Analysis, analysis of fourth quarter results, revised officer certifications and electronic filing of auditor's reports. The deadlines of these reports will be accelerated each year through 2006. Comments on this NOPR are due on August 22, 2003. At this time, we cannot predict the outcome of this NOPR.

Other Regulatory Matters. HIOS is subject to the jurisdiction of the FERC in accordance with the Natural Gas Act of 1938 and the Natural Gas Policy Act of 1978. HIOS operates under a FERC approved tariff that governs its operations, terms and conditions of service, and rates. We timely filed a required rate case for HIOS on December 31, 2002. The rate filing and tariff changes are based on HIOS' cost of service, which includes operating costs, a management fee and changes to depreciation rates and negative salvage amortization. We requested the rates be effective February 1, 2003, but the FERC suspended the rate increase until July 1, 2003, subject to refund. We have responded, and are continuing to respond, as new requests are received, to the FERC staff's data requests. The FERC has scheduled a hearing on this matter commencing November 17, 2003.

During the latter half of 2002, we experienced a significant variance between the fuel usage on HIOS and the fuel collected from our customers. We believe a series of events may have contributed to this variance, including two major storms that hit the Gulf Coast Region (and these assets) in late September and early October of 2002. We are taking numerous steps to determine the cause of the fuel differences, including a review of receipt and delivery measurement data. As of June 30, 2003, we had recorded fuel differences of approximately $11.3 million, which is included in other non-current assets. Depending on the outcome of our review, we expect to seek FERC approval to collect some or all of the fuel differences. At this time we are not able to determine what amount, if any, may be collectible from our customers. Any amount we are unable to resolve or collect from our customers may negatively impact our earnings.

In June 2002, Petal Gas Storage, which is also subject to the FERC's jurisdiction, filed with the FERC a certificate application to add additional gas storage capacity to Petal's storage system. The filing included a new storage cavern with a working gas capacity of 5 Bcf, the conversion and enlargement of an existing subsurface brine storage cavern to a gas storage cavern with a working capacity of 3 Bcf and related surface facilities, natural gas, water and brine transmission lines. In February 2003, the FERC approved the facilities proposed by Petal. We are currently in discussion with potential customers for the proposed new capacity.

In December 1999, GulfTerra Texas filed a petition with the FERC for approval of its rates for interstate transportation service. In June 2002, the FERC issued an order that required revisions to GulfTerra Texas' proposed maximum rates. The changes ordered by the FERC involve reductions to rate of return, depreciation rates and revisions to the proposed rate design, including a requirement to separately state rates for gathering service. FERC also ordered refunds to customers for the difference, if any, between the originally proposed levels and the revised rates ordered by the FERC. We believe the amount of any rate refund would be minimal since most transportation services are discounted from the maximum rate. GulfTerra Texas has established a reserve for refunds. In July 2002, GulfTerra Texas requested rehearing on certain issues raised by the FERC's order, including the depreciation rates and the requirement to separately state a gathering rate. GulfTerra Texas' request for rehearing has been granted and is pending before the FERC.

In July 2002, Falcon Gas Storage also requested late intervention and rehearing of the order. Falcon asserts that GulfTerra Texas' imbalance penalties and terms of service preclude third parties from offering imbalance management services. Meanwhile in December 2002, GulfTerra Texas amended its Statement of Operating Conditions to provide shippers the option of resolving daily imbalances using a third-party imbalance service provider. Falcon objected to the changes, complaining that imbalance resolution is the lowest priority of service. GulfTerra Texas responded to Falcon's objection and untimely intervention, repeating its request that Falcon's intervention be dismissed.

In December 2002, GulfTerra Texas requested FERC approval of market-based rates for interstate gas storage services performed at its Wilson storage facility. The filing was in compliance with a requirement to rejustify its existing rates or request new rates by December 20, 2002. Falcon also intervened in this filing, complaining that market-based rates should be denied because of their complaint about access on the GulfTerra Texas pipeline for third party imbalance services. On May 15, 2003, the FERC approved Wilson's market based rate proposal and dismissed Falcon's complaint.

Falcon Gas Storage Company, Inc. and its affiliate Hill-Lake Gas Storage, L.P. ("Falcon") filed a formal complaint in March 2003 at the Railroad Commission of Texas claiming that GulfTerra Texas' imbalance penalties and terms of service preclude third parties from offering hourly imbalance management services on the GulfTerra Texas system. GulfTerra Texas filed a response specifically denying Falcon's assertions and requesting that the complaint be denied.

While the outcome of all of our rates and regulatory matters cannot be predicted with certainty, based on information known to date, we do not expect the ultimate resolution of these matters will have a material adverse effect on our financial position, results of operations or cash flows. As new information becomes available or relevant developments occur, we will establish accruals as appropriate.

Joint Ventures

We conduct a portion of our business through joint venture arrangements we form to construct, operate and finance the development of our onshore and offshore midstream energy businesses. We are obligated to make our proportionate share of additional capital contributions to our joint ventures only to the extent that they are unable to satisfy their obligations from other sources including proceeds from credit arrangements.

Other Matters

As a result of current circumstances generally surrounding the energy sector, the creditworthiness of several industry participants has been called into question. As a result of these general circumstances, we have established an internal group to monitor our exposure to and determine, as appropriate, whether we should request prepayments, letters of credit or other collateral from our counterparties.

8. ACCOUNTING FOR HEDGING ACTIVITIES

A majority of our commodity purchases and sales, which relate to sales of oil and natural gas associated with our production operations, purchases and sales of natural gas associated with pipeline operations, sales of natural gas liquids associated with our processing plants and our gathering activities are at spot market or forward market prices. We use futures, forward contracts, and swaps to limit our exposure to fluctuations in the commodity markets and allow for a fixed cash flow stream from these activities.

In August 2002, we entered into a derivative financial instrument to hedge our exposure during 2003 to changes in natural gas prices relating to gathering activities in the San Juan Basin in anticipation of our acquisition of the San Juan assets. The derivative is a financial swap on 30,000 MMBtu per day whereby we receive a fixed price of $3.525 per MMBtu and pay a floating price based on the San Juan index. Beginning with the acquisition date in November 2002, we are accounting for this derivative as a cash flow hedge under

SFAS No. 133. In February 2003, we entered into an additional derivative financial instrument to continue to hedge our exposure during 2004 to changes in natural gas prices relating to gathering activities in the San Juan Basin. The derivative is a financial swap on 15,000 MMBtu per day whereby we receive a fixed price of $3.95 per MMBtu and pay a floating price based on the San Juan index. We are accounting for this derivative as a cash flow hedge under SFAS No. 133. As of June 30, 2003, the fair value of these cash flow hedges was a liability of $10.3 million. For the six months ended June 30, 2003, we reclassified a loss of approximately $6.0 million from accumulated other comprehensive income resulting in a reduction to earnings. No ineffectiveness exists in this hedging relationship because all purchase and sale prices are based on the same index and volumes as the hedge transaction. We estimate the entire amount will be reclassified from accumulated other comprehensive income as a reduction to earnings over the next 18 months and approximately $9.7 million will be reclassified as a reduction to earnings over the next twelve months.

Prior to June 30, 2003, in connection with our GulfTerra Intrastate Alabama operations, we had fixed price contracts with specific customers for the sale of predetermined volumes of natural gas for delivery over established periods of time. We entered into cash flow hedges in 2002 and 2003 to offset the risk of increasing natural gas prices. As of June 30, 2003, these cash flow hedges expired and we reclassified a gain of approximately $0.2 million from accumulated other comprehensive income to earnings. No ineffectiveness existed in this hedging relationship because all purchase and sale prices were based on the same index and volumes as the hedge transaction.

In January 2002, Poseidon entered into a two-year interest rate swap agreement to fix the variable portion of its LIBOR based interest rate on $75 million of its $185 million variable rate revolving credit facility at 3.49% over the life of the swap. Prior to April 2003, under its credit facility, Poseidon paid an additional 1.50% over the LIBOR rate resulting in an effective interest rate of 4.99% on the hedged notional amount. Beginning in April 2003, the additional interest Poseidon pays over LIBOR was reduced resulting in an effective fixed interest rate of 4.74% on the hedged notional amount. As of June 30, 2003, the fair value of its interest rate swap was a liability of $0.9 million resulting in accumulated other comprehensive loss of $0.9 million. We included our 36 percent share of this liability of $0.3 million as a reduction of our investment in Poseidon and as a loss in accumulated other comprehensive income which we estimate will be reclassified to earnings proportionately over the next six months. Additionally, we have recognized in income our 36 percent share of Poseidon's realized loss of $0.7 million for the six months ended June 30, 2003, or $0.2 million, through our earnings from unconsolidated affiliates.

In July 2003, to achieve a better mix of fixed rate debt and variable rate debt, we entered into an eight-year interest rate swap agreement to provide for a floating interest rate on our fixed 8½% $250 million senior subordinated notes that were issued in May 2001. With this swap agreement, we will pay the counterparty a LIBOR based interest rate plus a spread of 4.20% and receive a fixed rate of 8½%. We are accounting for this derivative as a fair value hedge.

The counterparty for our San Juan hedging activities is J. Aron and Company, a subsidiary of Goldman Sachs. We do not require collateral and do not anticipate non-performance by this counterparty. The counterparty for Poseidon's hedging activity is Credit Lyonnais. Poseidon does not require collateral and does not anticipate non-performance by this counterparty. Wachovia Bank is our counterparty on our new interest rate swap and we do not require collateral nor anticipate non-performance by this counterparty.

9. BUSINESS SEGMENT INFORMATION

Each of our segments are business units that offer different services and products that are managed separately since each segment requires different technology and marketing strategies. We have segregated our business activities into four distinct operating segments:

- Natural gas pipelines and plants;
- Oil and NGL logistics;
- Natural gas storage; and
- Platform services.

As a result of our sale of the Prince TLP and our nine percent overriding royalty interest in the Prince Field in April 2002, the results of operations from these assets are reflected as discontinued operations in our statements of income for all periods presented. Accordingly, the segment results do not reflect the results of operations for the Prince assets.

We measure segment performance using earnings before interest, income taxes, depreciation and amortization (EBITDA), which we formerly referred to as "Performance Cash Flows," or an asset's ability to generate income. EBITDA is used in the evaluation of our businesses and should not be considered as an alternative to net income as an indicator of our operating performance. EBITDA may not be a comparable measurement among different companies.

Following are results as of and for the periods ended June 30:

	Natural Gas Pipelines & Plants	Oil and NGL Logistics	Natural Gas Storage	Platform Services	Other[1]	Total
			(In thousands)			
Quarter Ended June 30, 2003						
Revenue from external customers	$ 199,517	$ 89,087	$ 10,871	$ 6,101	$ 4,533	$ 310,109
Intersegment revenue	30	—	186	758	(974)	—
Depreciation, depletion and amortization	17,079	2,167	2,919	1,360	1,321	24,846
Operating income	60,222	8,208	5,149	4,917	(610)	77,886
Earnings from unconsolidated affiliates	626	2,361	—	—	—	2,987
EBITDA	78,339	12,897	8,068	6,277	N/A	N/A
Assets	2,266,522	427,447	324,482	164,120	72,098	3,254,669
Quarter Ended June 30, 2002						
Revenue from external customers	$ 95,195	$ 9,750	$ 5,467	$ 5,165	$ 4,912	$ 120,489
Intersegment revenue	58	—	—	3,114	(3,172)	—
Depreciation, depletion and amortization	12,247	1,663	1,401	1,011	1,794	18,116
Operating income (loss)	34,857	5,725	690	6,423	(1,918)	45,777
Earnings from unconsolidated affiliates	—	4,012	—	—	—	4,012
EBITDA	47,114	12,069	2,091	7,493	N/A	N/A
Assets	1,402,890	189,574	299,556	107,012	76,974	2,076,006

(1) Represents predominately our oil and natural gas production activities as well as intersegment eliminations.

	Natural Gas Pipelines & Plants	Oil and NGL Logistics	Natural Gas Storage	Platform Services	Other(1)	Total
			(In thousands)			
Six Months Ended June 30, 2003						
Revenue from external customers	$ 396,706	$149,886	$ 22,477	$ 10,483	$ 9,483	$ 589,035
Intersegment revenue	68	—	278	1,404	(1,750)	—
Depreciation, depletion and amortization	33,632	4,364	5,881	2,560	2,106	48,543
Operating income	120,654	13,649	9,188	7,952	1,550	152,993
Earnings from unconsolidated affiliates	1,255	5,048	—	—	—	6,303
EBITDA	156,141	24,497	15,069	10,512	N/A	N/A
Assets	2,266,522	427,447	324,482	164,120	72,098	3,254,669
Six Months Ended June 30, 2002						
Revenue from external customers	$ 135,555	$ 18,576	$ 9,855	$ 9,627	$ 8,420	$ 182,033
Intersegment revenue	117	—	—	6,223	(6,340)	—
Depreciation, depletion and amortization	18,752	3,131	2,802	2,103	3,877	30,665
Operating income	48,527	10,472	1,998	12,516	(5,024)	68,489
Earnings from unconsolidated affiliates	—	7,373	—	—	—	7,373
EBITDA	67,292	22,784	4,800	20,315	N/A	N/A
Assets	1,402,890	189,574	299,556	107,012	76,974	2,076,006

(1) Represents predominately our oil and natural gas production activities as well as intersegment eliminations.

A reconciliation of our segment EBITDA to our net income is as follows:

	Quarter Ended June 30,		Six Months Ended June 30,	
	2003	2002	2003	2002
Natural gas pipeline & plants	$ 78,339	$ 47,114	$156,141	$ 67,292
Oil & NGL logistics	12,897	12,069	24,497	22,784
Natural gas storage	8,068	2,091	15,069	4,800
Platform services	6,277	7,493	10,512	20,315
Segment EBITDA	105,581	68,767	206,219	115,191
Plus: Other, nonsegment results	3,011	2,212	8,277	4,306
Earnings from unconsolidated affiliates	2,987	4,012	6,303	7,373
Income from discontinued operations	—	60	—	4,445
Cumulative effect of accounting change	—	—	1,690	—
Less: Interest and debt expense	31,838	21,534	66,324	33,292
Loss due to write-off of debt issuance costs	—	—	3,762	—
Depreciation, depletion and amortization	24,846	18,116	48,543	30,665
Cash distributions from unconsolidated affiliates	3,520	4,680	8,230	9,180
Net cash payment received from El Paso Corporation	2,078	1,917	4,118	3,799
Discontinued operations of Prince facilities	—	59	—	6,508
Net income	$ 49,297	$ 28,745	$ 91,512	$ 47,871

10. INVESTMENTS IN UNCONSOLIDATED AFFILIATES

We hold investments in various affiliates which we account for using the equity method of accounting. Summarized financial information for these investments are as follows:

Six Months Ended June 30, 2003
(In thousands)

	Coyote	Deepwater Gateway	Poseidon	Total
Ownership interest	50%	50%	36%	
Operating results data:				
Operating revenues	$3,825	$—	$ 658,597	
Crude oil purchases	—	—	(635,390)	
Gross margin	3,825	—	23,207	
Other income	4	23	35	
Operating expenses	(242)	—	(2,160)	
Depreciation	(690)	—	(4,169)	
Other expenses	(387)	(5)	(2,835)	
Net income	$2,510	$18	$ 14,078	
Our share:				
Allocated income	$1,255	$ 9	$ 5,068	
Adjustments[1]	—	(9)	(20)	
Earnings from unconsolidated affiliates	$1,255	$—	$ 5,048	$6,303
Allocated distributions	$1,750	$—	$ 6,480	$8,230

Six Months Ended June 30, 2002
(In thousands)

	Poseidon
Ownership interest	36%
Operating results data:	
Operating revenues	$ 535,567
Crude oil purchases	(505,824)
Gross margin	29,743
Other income	45
Operating expenses	(1,704)
Depreciation	(4,137)
Other expenses	(3,468)
Net income	$ 20,479
Our share:	
Allocated income	$ 7,372
Adjustments[1]	1
Earnings from unconsolidated affiliate	$ 7,373
Allocated distributions	$ 9,180

(1) We recorded adjustments primarily for differences from estimated earnings reported in our Quarterly Report on Form 10-Q and actual earnings reported in the unaudited financial statements of our unconsolidated affiliates.

In June 2003, we formed Cameron Highway Oil Pipeline Company and contributed to this newly formed company the $458 million Cameron Highway oil pipeline system construction project. Cameron Highway is responsible for building and operating the pipeline, which is scheduled for completion during the third quarter of 2004.

In connection with the construction of the Cameron Highway oil pipeline, we entered into producer agreements with three major anchor producers, BP Exploration & Production Company (BP Exploration), BHP Billiton Petroleum (Deepwater), Inc. (BHP), and Union Oil Company of California (Unocal), which agreements were assigned to and assumed by Cameron Highway. The producer agreements require construction of the 390-mile Cameron Highway oil pipeline. We are obligated to make additional capital contributions to Cameron Highway, to the extent that the construction costs for the pipeline exceed Cameron Highway's capital resources, including our initial equity contributions and proceeds from Cameron Highway's project loan facility.

In July 2003, we sold a 50 percent interest in Cameron Highway to Valero Energy Corporation for $86 million, forming a joint venture with Valero. Valero paid us approximately $70 million at closing, including $51 million representing 50 percent of the capital investment expended through that date for the pipeline project. In July 2003, we recognized $19 million as a gain from the sale of long-lived assets. In addition, Valero will pay us a total of $16 million, $5 million to be paid once the system is completed and the remaining $11 million by the end of 2006. We expect to reflect the receipts of these additional amounts in the periods received as gains from the sale of long-lived assets in our income statement. In connection with the formation of the Cameron Highway joint venture, Valero agreed to pay their proportionate share of pipeline construction costs that exceed Cameron Highways's capital resources, including the initial equity contributions and proceeds from Cameron Highway's project loan facility.

The Cameron Highway oil pipeline system project is expected to be funded with 29 percent equity through capital contributions from the Cameron Highway partners and 71 percent debt through a $325 million project loan facility, consisting of a $225 million construction loan and $100 million of senior secured notes. See Note 6 for additional discussion of the project loan facility.

11. RELATED PARTY TRANSACTIONS

Our transactions with related parties and affiliates are as follows:

	Quarter Ended June 30,		Six Months Ended June 30,	
	2003	2002	2003	2002
	(In thousands)			
Revenues received from related parties				
Natural gas pipelines and plants	$26,064	$47,610	$49,014	$60,464
Oil and NGL logistics	8,975	6,992	15,844	13,225
Natural gas storage	—	68	—	67
Other	—	2,673	—	4,946
	$35,039	$57,343	$64,858	$78,702
Expenses paid to related parties				
Cost of natural gas, oil and other products	$ 5,842	$ 6,133	$20,797	$14,534
Operating expenses	22,093	14,680	45,810	23,616
	$27,935	$20,813	$66,607	$38,150
Reimbursements received from related parties				
Operating expenses	$ 676	$ 525	$ 1,201	$ 1,050

There have been no changes to our related party relationships, except as described below, from those described in Note 9 of our audited financial statements filed in our 2002 Form 10-K.

Revenues received from related parties for the quarters ended June 30, 2003 and 2002, were approximately 11 percent and 48 percent of our total revenue. Revenues received from related parties for the six months ended June 30, 2003 and 2002, were approximately 11 percent and 43 percent of our total revenue. Revenues received from El Paso Field Services increased $8.5 million from the first quarter of 2003 primarily as a result of higher natural gas and NGL volumes sold to El Paso Field Services from our Big Thicket assets and from higher volumes on the Texas NGL assets that were reactivated in 2003. Also, we have undertaken efforts to reduce our transactions with El Paso Merchant Energy North America Company (Merchant Energy) and as of June 30, 2003, we have replaced all our month-to-month arrangements with similar arrangements with third parties.

The following table provides summary data categorized by our related parties:

	Quarter Ended June 30,		Six Months Ended June 30,	
	2003	2002	2003	2002
	(In thousands)			
Revenues received from related parties				
El Paso Corporation				
El Paso Merchant Energy North America Company	$ 7,791	$30,212	$18,603	$36,165
El Paso Production Company	2,074	2,472	4,432	3,564
Tennessee Gas Pipeline Company	38	—	93	—
El Paso Field Services	25,136	24,659	41,730	38,973
	$35,039	$57,343	$64,858	$78,702
Cost of natural gas, oil and other products purchased from related parties				
El Paso Corporation				
El Paso Merchant Energy North America Company	$ 5,427	$ 3,548	$15,705	$10,758
El Paso Production Company	—	1,137	—	2,251
Tennessee Gas Pipeline Company	—	249	—	249
El Paso Field Services	346	—	5,023	—
El Paso Natural Gas Company	17	1,159	17	1,159
Southern Natural Gas	52	40	52	117
	$ 5,842	$ 6,133	$20,797	$14,534
Operating expenses paid to related parties				
El Paso Corporation				
El Paso Field Services	$21,979	$14,545	$45,603	$23,371
Unconsolidated Subsidiaries				
Poseidon Oil Pipeline Company	114	135	207	245
	$22,093	$14,680	$45,810	$23,616
Reimbursements received from related parties				
Unconsolidated Subsidiaries				
Poseidon Oil Pipeline Company	$ 676	$ 525	$ 1,201	$ 1,050

At June 30, 2003, and December 31, 2002, our accounts receivable due from related parties was $61.3 million and $83.8 million. At June 30, 2003 and December 31, 2002, our accounts payable due to related parties was $80.8 million and $86.1 million.

Our accounts receivable due from related parties consisted of the following as of:

	June 30, 2003	December 31, 2002
	(In thousands)	
El Paso Corporation		
El Paso Production Company	$ 1,342	$ 4,346
El Paso Merchant Energy North America Company	31,288	30,512
Tennessee Gas Pipeline Company	2,921	930
El Paso Field Services	18,970	36,071
El Paso Natural Gas Company	2,637	1,033
Other	1,111	1,298
	58,269	74,190
Unconsolidated Subsidiaries		
Deepwater Gateway	3,052	9,636
Other	18	—
	3,070	9,636
Total	$61,339	$83,826

Our accounts payable due to related parties consisted of the following as of:

	June 30, 2003	December 31, 2002
	(In thousands)	
El Paso Corporation		
El Paso Merchant Energy North America Company	$ 7,243	$ 8,871
El Paso Production Company	17,345	14,518
El Paso Field Services	43,290	55,648
Tennessee Gas Pipeline Company	651	1,319
El Paso Natural gas Company	1,994	1,475
El Paso Corporation	3,604	4,181
Other	882	132
	75,009	86,144
Unconsolidated Subsidiaries		
Deepwater Gateway	2,242	—
Copper Eagle	3,525	—
	5,767	—
Total	$80,776	$86,144

Other Matters

In connection with the sale of some of our Gulf of Mexico assets in January 2001, El Paso Corporation agreed to make quarterly payments to us of $2.25 million for three years beginning March 2001 and $2 million in the first quarter of 2004. The present value of the amounts due from El Paso Corporation were classified as follows:

	June 30, 2003	December 31, 2002
	(In thousands)	
Accounts receivable, net	$6,244	$ 8,403
Other noncurrent assets	—	1,960
	$6,244	$10,363

In addition to the related party transactions discussed above, pursuant to the terms of many of the purchase and sale agreements we have entered into with various entities controlled directly or indirectly by El Paso Corporation, we have been indemnified for potential future liabilities, expenses and capital requirements above a negotiated threshold. Specifically, an indirect subsidiary of El Paso Corporation has indemnified us for specific litigation matters to the extent the ultimate resolutions of these matters result in judgments against us. For a further discussion of these matters see Note 7, Commitments and Contingencies, Legal Proceedings. Some of our agreements obligate certain indirect subsidiaries of El Paso Corporation to pay for capital costs related to maintaining assets which were acquired by us, if such costs exceed negotiated thresholds. We have made no such claims for reimbursement to date but may make claims based on our 2002 expenditures and on our expected 2003 expenditure requirements.

We have also entered into capital contribution arrangements with entities owned by El Paso Corporation, including its regulated pipelines, in the past, and will most likely do so in the future, as part of our normal commercial activities in the Gulf of Mexico. We have agreements to receive from subsidiaries of El Paso Corporation the following: $2 million from Tennessee Gas Pipeline for our Medusa project, $7.0 million from El Paso Field Services for the Marco Polo pipeline and $6.1 million from ANR Pipeline Company for our Phoenix project. Regulated pipelines often contribute capital toward the construction costs of gathering facilities owned by others which are, or will be, connected to their pipelines. El Paso Field Services' contribution is in anticipation of additional natural gas that will flow through to its onshore natural gas processing facilities.

12. GUARANTOR FINANCIAL INFORMATION

As of June 30, 2003, our revolving credit facility, GulfTerra Holding term credit facility and senior secured term loan are guaranteed by each of our subsidiaries, excluding our unrestricted subsidiaries (Matagorda Island Area Gathering System, Arizona Gas Storage, L.L.C. and GulfTerra Arizona Gas, L.L.C., Cameron Highway Pipeline GPI, L.L.C. (CHOPS GPI), Cameron Highway Pipeline II, L.P. (CHOPS II), Cameron Highway Pipeline III, L.P. (CHOPS III), and Cameron Highway Oil Pipeline Company (Cameron Highway), and our general partner, and are collateralized by our general partner's general and administrative services agreement and substantially all of our assets. In addition, all of our senior subordinated notes are jointly, severably, fully and unconditionally guaranteed by us and all of our subsidiaries, excluding our unrestricted subsidiaries. As part of our Cameron Highway transaction, in July 2003 we sold CHOPS GPI, CHOPS II and CHOPS III and, as a result, Cameron Highway became an unconsolidated affiliate in which we have a 50 percent joint venture ownership interest. The consolidating eliminations column on our condensed consolidating balance sheets below eliminates our investment in consolidated subsidiaries, intercompany payables and receivables and other transactions between subsidiaries. The consolidating eliminations column in our condensed consolidating statements of income and cash flows eliminates earnings from our consolidated affiliates.

Non-guarantor subsidiaries as of and for the quarter and six months ended June 30, 2003, consisted of our unrestricted subsidiaries. Non-guarantor subsidiaries as of and for the quarter ended June 30, 2002, consisted of our GulfTerra Holding Subsidiaries, which own the EPN Holding assets and equity interests in GulfTerra Holding. Non-guarantor subsidiaries for the quarter ended March 31, 2002 consisted of Argo and Argo I which owned the Prince TLP. As a result of our disposal of the Prince TLP and our related overriding royalty interest in April 2002, the results of operations and net book value of these assets are reflected as discontinued operations in our statements of income and assets held for sale in our balance sheets and Argo and Argo I became guarantor subsidiaries.

Condensed Consolidating Statements of Income
For the Quarter Ended June 30, 2003

	Issuer	Non-guarantor Subsidiaries	Guarantor Subsidiaries	Consolidating Eliminations	Consolidated Total
			(In thousands)		
Operating revenues	$ —	$229	$309,880	$ —	$310,109
Operating expenses					
Cost of natural gas, oil and other products	—	—	158,463	—	158,463
Operation and maintenance	2,737	68	45,746	—	48,551
Depreciation, depletion and amortization	37	10	24,799	—	24,846
Loss on sale of long-lived assets	—	—	363	—	363
	2,774	78	229,371	—	232,223
Operating income (loss)	(2,774)	151	80,509	—	77,886
Other income (loss)					
Earnings from consolidated affiliates	62,892	—	—	(62,892)	—
Earnings from unconsolidated affiliates	—	—	2,987	—	2,987
Minority interest expense	—	(47)	—	—	(47)
Other income	203	—	106	—	309
Interest and debt expense	11,024	—	20,814	—	31,838
Net income (loss)	$49,297	$104	$ 62,788	$(62,892)	$ 49,297

Condensed Consolidating Statements of Income
For the Quarter Ended June 30, 2002

	Issuer	Non-guarantor Subsidiaries	Guarantor Subsidiaries	Consolidating Eliminations	Consolidated Total
		(In thousands)			
Operating revenues	$ —	$61,456	$59,033	$ —	$120,489
Operating expenses					
Cost of natural gas, oil and other products	—	18,940	8,403	—	27,343
Operation and maintenance	797	13,046	15,410	—	29,253
Depreciation, depletion and amortization	38	5,414	12,664	—	18,116
	835	37,400	36,477	—	74,712
Operating income (loss)	(835)	24,056	22,556	—	45,777
Other income (loss)					
Earnings from consolidated affiliates	17,209	—	11,613	(28,822)	—
Earnings from unconsolidated affiliates	—	—	4,012		4,012
Minority interest expense	—	(5)	—	—	(5)
Other income (loss)	426	(6)	15	—	435
Interest and debt expense	(11,945)	12,432	21,047	—	21,534
Income from continuing operations	28,745	11,613	17,149	(28,822)	28,685
Income from discontinued operations	—	—	60	—	60
Net income	$28,745	$11,613	$17,209	$(28,822)	$ 28,745

Condensed Consolidating Statements of Income
For the Six Months Ended June 30, 2003

	Issuer	Non-guarantor Subsidiaries	Guarantor Subsidiaries	Consolidating Eliminations	Consolidated Total
			(In thousands)		
Operating revenues	$ —	$506	$588,529	$ —	$589,035
Operating expenses					
Cost of natural gas, oil and other products	—	—	298,047	—	298,047
Operation and maintenance, net	3,204	142	85,849	—	89,195
Depreciation, depletion and amortization	74	21	48,448	—	48,543
Loss on sale of long-lived assets	—	—	257	—	257
	3,278	163	432,601	—	436,042
Operating income (loss)	(3,278)	343	155,928	—	152,993
Other income (loss)					
Earnings from consolidated affiliates	124,397	—	—	(124,397)	—
Earnings from unconsolidated affiliates	—	—	6,303	—	6,303
Minority interest expense	—	(80)	—	—	(80)
Other income	451	—	241	—	692
Interest and debt expense	26,296	—	40,028	—	66,324
Loss due to write-off of debt issuance costs	3,762	—	—	—	3,762
Income from continuing operations	91,512	263	122,444	(124,397)	89,822
Cumulative effect of accounting change	—	—	1,690	—	1,690
Net income	$ 91,512	$263	$124,134	$(124,397)	$ 91,512

Condensed Consolidating Statements of Income
For the Six Months Ended June 30, 2002

	Issuer	Non-guarantor Subsidiaries	Guarantor Subsidiaries	Consolidating Eliminations	Consolidated Total
		(In thousands)			
Operating revenues	$ —	$ 61,456	$120,577	$ —	$182,033
Operating expenses					
Cost of natural gas, oil and other products	—	18,940	20,561	—	39,501
Operations and maintenance, net	4,069	13,046	26,578	—	43,693
Depreciation, depletion and amortization	199	5,414	25,052	—	30,665
Gain on sale of long-lived assets	—	—	(315)	—	(315)
	4,268	37,400	71,876	—	113,544
Operating income (loss)	(4,268)	24,056	48,701	—	68,489
Other income (loss)					
Earnings from consolidated affiliates	28,893	—	15,617	(44,510)	—
Earnings from unconsolidated affiliates	—	—	7,373	—	7,373
Minority interest expense	—	(5)	—	—	(5)
Other income	862	(6)	5	—	861
Interest and debt expense	(22,384)	12,432	43,244	—	33,292
Income from continuing operations	47,871	11,613	28,452	(44,510)	43,426
Income from discontinued operations	—	4,004	441	—	4,445
Net income	$47,871	$ 15,617	$ 28,893	$(44,510)	$ 47,871

Condensed Consolidating Balance Sheets
June 30, 2003

	Issuer	Non-guarantor Subsidiaries	Guarantor Subsidiaries	Consolidating Eliminations	Consolidated Total
			(In thousands)		
Current assets					
Cash and cash equivalents	$ 8,888	$ —	$ 8,765	$ —	$ 17,653
Accounts receivable, net					
Trade	—	3,659	135,893	—	139,552
Affiliates	751,650	157	62,060	(752,528)	61,339
Affiliated note receivable	—	—	17,100	—	17,100
Other current assets	2,280	—	3,244	—	5,524
Total current assets	762,818	3,816	227,062	(752,528)	241,168
Property, plant and equipment, net	7,226	452	2,880,038	—	2,887,716
Intangible assets	—	—	3,489	—	3,489
Investment in unconsolidated affiliates	—	5,394	71,896	—	77,290
Investment in consolidated affiliates	1,909,049	—	634	(1,909,683)	—
Other noncurrent assets	201,737	—	13,268	(169,999)	45,006
Total assets	$2,880,830	$9,662	$3,196,387	$(2,832,210)	$3,254,669
Current liabilities					
Accounts payable					
Trade	$ —	$ 37	$ 113,969	$ —	$ 114,006
Affiliates	22,218	3,555	807,531	(752,528)	80,776
Accrued interest	12,266	—	1,324	—	13,590
Current maturities of senior secured term loan	5,000	—	—	—	5,000
Other current liabilities	4,204	1	9,652	—	13,857
Total current liabilities	43,688	3,593	932,476	(752,528)	227,229
Revolving credit facility	415,146	—	—	—	415,146
Senior secured term loans, less current maturities	152,500	—	160,000	—	312,500
Long-term debt	1,157,606	—	—	—	1,157,606
Other noncurrent liabilities	—	—	198,045	(169,999)	28,046
Minority interest	—	2,252	—	—	2,252
Partners' capital	1,111,890	3,817	1,905,866	(1,909,683)	1,111,890
Total liabilities and partners' capital	$2,880,830	$9,662	$3,196,387	$(2,832,210)	$3,254,669

Condensed Consolidating Balance Sheets
December 31, 2002

	Issuer	Non-guarantor Subsidiaries	Guarantor Subsidiaries	Consolidating Eliminations	Consolidated Total
			(In thousands)		
Current assets					
Cash and cash equivalents	$ 20,777	$ —	$ 15,322	$ —	$ 36,099
Accounts receivable, net					
Trade	—	74	139,445	—	139,519
Affiliates	709,230	3,055	67,513	(695,972)	83,826
Affiliated note receivable	—	—	17,100	—	17,100
Other current assets	1,118	—	2,333	—	3,451
Total current assets	731,125	3,129	241,713	(695,972)	279,995
Property, plant and equipment, net	6,716	454	2,717,768	—	2,724,938
Intangible assets	—	—	3,970	—	3,970
Investment in unconsolidated affiliates	—	5,197	73,654	—	78,851
Investment in consolidated affiliates	1,787,767	—	693	(1,788,460)	—
Other noncurrent assets	205,262	—	7,879	(169,999)	43,142
Total assets	$2,730,870	$8,780	$3,045,677	$(2,654,431)	$3,130,896
Current liabilities					
Accounts payable					
Trade	$ —	$ 302	$ 126,422	$ —	$ 126,724
Affiliates	18,867	2,982	760,267	(695,972)	86,144
Accrued interest	14,221	—	807	—	15,028
Current maturities of senior secured term loan	5,000	—	—	—	5,000
Other current liabilities	1,645	5	19,545	—	21,195
Total current liabilities	39,733	3,289	907,041	(695,972)	254,091
Revolving credit facility	491,000	—	—	—	491,000
Senior secured term loans, less current maturities	392,500	—	160,000	—	552,500
Long-term debt	857,786	—	—	—	857,786
Other noncurrent liabilities	(1)	—	193,725	(169,999)	23,725
Minority interest	—	1,942	—	—	1,942
Partners' capital	949,852	3,549	1,784,911	(1,788,460)	949,852
Total liabilities and partners' capital	$2,730,870	$8,780	$3,045,677	$(2,654,431)	$3,130,896

Condensed Consolidating Statements of Cash Flows
For the Six Months ended June 30, 2003

	Issuer	Non-guarantor Subsidiaries	Guarantor Subsidiaries	Consolidating Eliminations	Consolidated Total
			(In thousands)		
Cash flows from operating activities					
Net income	$ 91,512	$ 263	$ 124,134	$(124,397)	$ 91,512
Less cumulative effect of accounting change	—	—	1,690	—	1,690
Income from continuing operations	91,512	263	122,444	(124,397)	89,822
Adjustments to reconcile net income to net cash provided by operating activities					
Depreciation, depletion and amortization	74	21	48,448	—	48,543
Distributed earnings of unconsolidated affiliates					
Earnings from unconsolidated affiliates	—	—	(6,303)	—	(6,303)
Distributions from unconsolidated affiliates	—	—	8,230	—	8,230
Loss on sale of long-lived assets	—	—	257	—	257
Write-off of debt issuance costs	3,762	—	—	—	3,762
Other noncash items	4,286	310	(76)	—	4,520
Working capital changes, net of effects of acquisitions and noncash transactions	15,333	(546)	(29,452)	—	(14,665)
Net cash provided by operating activities	114,967	48	143,548	(124,397)	134,166
Cash flows from investing activities					
Additions to property, plant and equipment	(584)	(19)	(206,408)	—	(207,011)
Proceeds from sale of assets	—	—	3,215	—	3,215
Additions to investments in unconsolidated affiliates	—	(197)	—	—	(197)
Net cash used in investing activities	(584)	(216)	(203,193)	—	(203,993)
Cash flows from financing activities					
Net proceeds from revolving credit facility	223,000		—	—	223,000
Repayments of revolving credit facility	(298,854)	—	—	—	(298,854)
Repayment of senior secured acquisition term loan	(237,500)	—	—	—	(237,500)
Repayment of senior secured term loan	(2,500)	—	—	—	(2,500)
Net proceeds from issuance of long-term debt	292,479	—	—	—	292,479
Net proceeds from issuance of common units and Series F convertible units	182,182	—	—	—	182,182
Advances with affiliates	(177,653)	168	53,088	124,397	—
Distributions to partners	(107,427)	—	—	—	(107,427)
Contribution from General Partner	1	—	—	—	1
Net cash provided by (used in) financing activities	(126,272)	168	53,088	124,397	51,381
Increase (decrease) in cash and cash equivalents	$ (11,889)	$ —	$ (6,557)	$ —	(18,446)
Cash and cash equivalents					
Beginning of period					36,099
End of period					$ 17,653
Schedule of noncash financing activities:					
Contribution from General Partner and Redemption of Series B units	$ 1,788	$ —	$ —	$ —	$ 1,788

Condensed Consolidating Statements of Cash Flows
For the Six Months ended June 30, 2002

	Issuer	Non-guarantor Subsidiaries	Guarantor Subsidiaries	Consolidating Eliminations	Consolidated Total
			(In thousands)		
Cash flows from operating activities					
Net income	$ 47,871	$ 15,617	$ 28,893	$(44,510)	$ 47,871
Less income from discontinued operations	—	4,004	441	—	4,445
Income from continuing operations	47,871	11,613	28,452	(44,510)	43,426
Adjustments to reconcile net income to net cash provided by operating activities					
Depreciation, depletion and amortization	199	5,414	25,052	—	30,665
Distributed earnings of unconsolidated affiliates					
Earnings from unconsolidated affiliates	—	—	(7,373)	—	(7,373)
Distributions from unconsolidated affiliates	—	—	9,180	—	9,180
Gain on sale of long-lived assets	—	—	(315)	—	(315)
Other noncash items	2,229	(2,376)	1,642	—	1,495
Working capital changes, net of effects of acquisitions and noncash transactions	(23,334)	(19,523)	22,343	—	(20,514)
Net cash provided by (used in) continuing operations	26,965	(4,872)	78,981	(44,510)	56,564
Net cash provided by discontinued operations	—	4,631	406	—	5,037
Net cash provided by (used in) operating activities	26,965	(241)	79,387	(44,510)	61,601
Cash flows from investing activities					
Additions to property, plant and equipment	(1,700)	(2,090)	(87,528)	—	(91,318)
Proceeds from sale of assets	—	—	5,460	—	5,460
Additions to investments in unconsolidated affiliates	—	—	(14,144)	—	(14,144)
Cash paid for acquisitions, net cash acquired	—	(730,166)	—	—	(730,166)
Net cash used in investing activities of continuing operations	(1,700)	(732,256)	(96,212)	—	(830,168)
Net cash provided by (used in) investing activities of discontinued operations	—	(3,523)	190,000	—	186,477
Net cash provided by (used in) investing activities	(1,700)	(735,779)	93,788	—	(643,691)
Cash flows from financing activities					
Net proceeds from revolving credit facility	223,884	—	—	—	223,884
Repayments of revolving credit facility	(10,000)	—	—	—	(10,000)
Net proceeds from GulfTerra Holding term credit facility	—	7,000	—	—	7,000
Net proceeds from GulfTerra Holding term loan	—	530,529	—	—	530,529
Repayment of senior secured term loan	—	(375,000)	—	—	(375,000)
Repayment of Argo term loan	—	—	(95,000)	—	(95,000)
Net proceeds from issuance of long-term debt	229,757	—	—	—	229,757
Net proceeds from issuance of common units	149,309	—	—	—	149,309
Advances with affiliates	(543,739)	590,212	(90,983)	44,510	—
Distributions to partners	(73,214)	—	—	—	(73,214)
Contribution from General Partner	560	—	—	—	560
Net cash provided by (used in) financing activities of continuing operations	(23,443)	752,741	(185,983)	44,510	587,825
Net cash used in financing activities of discontinued operations	—	(3)	(1)	—	(4)
Net cash provided by (used in) financing activities	(23,443)	752,738	(185,984)	44,510	587,821
Increase (decrease) in cash and cash equivalents	$ 1,822	$ 16,718	$ (12,809)	$ —	5,731
Cash and cash equivalents					
Beginning of period					13,084
End of period					$ 18,815

13. NEW ACCOUNTING PRONOUNCEMENTS

In April 2003, the FASB issued SFAS No. 149, *Amendment of Statement 133 on Derivative Instruments and Hedging Activities.* This statement amends and clarifies financial accounting and reporting for derivative instruments, including certain derivative instruments embedded in other contracts and for hedging activities. The statement is effective for contracts entered into or modified after June 30, 2003 and for hedging relationships designated after June 30, 2003, except for provisions that relate to SFAS No. 133 implementation issues that have been effective for the fiscal quarter that began prior to June 15, 2003, which are applicable on their respective effective dates. We are required to adopt the provisions of this statement prospectively, unless otherwise prescribed. We have adopted this pronouncement on a prospective basis as of July 1, 2003.

In May 2003, the FASB issued SFAS No. 150, *Accounting for Certain Financial Instruments with Characteristics of both Liabilities and Equity*. This statement provides guidance on the classification of financial instruments, as equity, as liabilities, or as both liabilities and equity. The provisions of SFAS No. 150 are effective for all financial instruments entered into or modified after May 31, 2003, and otherwise is effective at the beginning of the first interim period beginning July 1, 2003. We adopted the provisions of SFAS No. 150 on July 1, 2003, and our adoption had no material impact on our financial statements.

Item 2. Management's Discussion and Analysis of Financial Condition and Results of Operations

The information contained in Item 2 updates, and you should read it in conjunction with, information disclosed in Part II, Items 7, 7A and 8, in our Annual Report on Form 10-K for the year ended December 31, 2002, in addition to the interim financial statements and notes presented in Item 1 of this Quarterly Report on Form 10-Q.

General Partner Relationship

Our corporate governance structure and independence initiatives

This year we have continued to improve our corporate governance model, which currently meets the standards established by the SEC and the NYSE. During the first quarter of 2003, we identified and evaluated a number of changes that could be made to our corporate structure to better address potential conflicts of interest and to better balance the risks and rewards of significant relationships with our affiliates, which we refer to as Independence Initiatives. Through July 2003, we have implemented the following:

- added an additional independent director to our board of directors, bringing the number of independent directors to four of the six-member board;
- established a governance and compensation committee of our board of directors consisting solely of independent directors which is responsible for establishing performance measures and making recommendations to El Paso Corporation concerning total compensation of its employees performing duties for us;
- changed our name to GulfTerra Energy Partners, L.P.;
- received a letter of credit from El Paso Merchant Energy North America totaling $5.1 million regarding our existing customer/contractual relationships with them;
- modified our partnership agreement to: (1) eliminate El Paso Corporation's right to vote its common units with respect to the removal of the general partner; (2) effectively reduce the third party common unit vote required to remove the general partner from 72 percent to 67 percent; and (3) require the unanimous vote of the general partner's board of directors before the general partner or we can voluntarily initiate bankruptcy proceedings;
- completed a resource support agreement with El Paso Corporation; and
- reorganized our structure, further reducing our interrelationships with El Paso Corporation, resulting in our general partner being a Delaware limited liability company that is not permitted to have:
  - material assets other than its interests in us;
  - material operations other than those relating to our operations;
  - material debt or other obligations other than those owed to us or our creditors;
  - material liens other than those securing obligations owed to us or our creditors; or
  - employees.

We are in the process of implementing the following Independence Initiatives:

- adding one more independent director to the board of directors, and
- negotiating a master netting agreement that could partially mitigate our risks associated with our ongoing contractual arrangements with El Paso Corporation or any of its subsidiaries. Approval must be received from our general partner's board of directors and from El Paso Corporation prior to executing the master netting agreement.

Under the partnership agreement, our general partner has the responsibility to, among other things, manage and operate our assets. In addition, our general partner had agreed not to voluntarily withdraw as general partner prior to December 31, 2002. Now that this obligation of the general partner has expired, our general partner can withdraw with 90 days notice. We have no employees today, a condition that is common among MLPs. Although this arrangement has worked well for us in the past and continues to work well for us, we are evaluating the direct employment of the personnel who manage the day-to-day operations of our assets.

Our relationship with El Paso Corporation

El Paso Corporation, a NYSE-listed company, is a leading provider of natural gas services and the largest pipeline company in North America. Through its subsidiaries, El Paso Corporation:

- owns 100 percent of our general partner, which means that, historically, El Paso Corporation and its affiliates have employed the personnel who operate our businesses. We reimburse our general partner and its affiliates for the costs they incur on our behalf, and we pay our general partner its proportionate share of distributions —relating to its one percent general partnership interest and the related incentive distributions —we make to our partners each calendar quarter. Furthering our Independence Initiatives efforts, El Paso Corporation has announced its intention to sell between 5 and 10 percent of its ownership interest in our general partner to a third party. El Paso Corporation has the sole responsibility to determine the ultimate ownership status of the general partner interest.

- is a significant stake-holder in us — it owns approximately 23.4 percent, or 11,674,245, of our common units (decreased from 26.5 percent as a result of our common unit offerings during the second quarter 2003), all 10,937,500 of our Series C units, which we issued in November 2002 for $350 million, all 124,014 of our outstanding Series B preference units, with a liquidation value of approximately $163.6 million at June 30, 2003 and our one percent general partner interest. As holders of some of our common units and all of our Series C units, subsidiaries of El Paso Corporation receive their proportionate share of distributions we make to our partners each calendar quarter. In July 2003, we filed a registration statement on Form S-3 to register for resale 2,000,000 of the common units owned by affiliates of El Paso Corporation.

- is a customer of ours. As with other large energy companies, we have entered into a number of contracts with El Paso Corporation and its affiliates.

As discussed previously, we have implemented, and are in the process of implementing, a number of Independence Initiatives that are designed to help us better manage the rewards and risks relating to our relationship with El Paso Corporation. However, even in the light of these Independence Initiatives or any other arrangements, we may still be adversely affected if El Paso Corporation continues to suffer financial stress.

Related Party Transactions

In our normal course of business we enter into transactions with various entities controlled directly or indirectly by El Paso Corporation.

Revenues received from El Paso Field Services increased by $8.5 million from the first quarter of 2003 primarily as a result of higher natural gas and NGL volumes sold to El Paso Field Services from our Big Thicket assets and from higher volumes on the Texas NGL assets that were reactivated in 2003.

For the quarter ended June 30, 2003, $7.8 million of our related party revenue came from Merchant Energy. In November 2002, El Paso Corporation announced its intention to exit the energy trading business. As of June 30, 2003, we have replaced all our month-to-month, market priced sales of natural gas to Merchant Energy with similar arrangements with third parties. In the quarter ended June 30, 2003, these natural gas transportation and storage agreements represented revenue of approximately $7.7 million. Currently, we have a $5.1 million letter of credit from Merchant Energy representing two months of transportation revenues. As of July 2003, Merchant Energy continues to fully utilize these agreements; however, Merchant Energy has agreed to transfer the natural gas transportation and storage agreements they have with us to El Paso Field Services. This transfer is expected to be completed by year end.

In connection with our San Juan assets acquisition, we entered into a 10-year transportation agreement with El Paso Field Services beginning January 1, 2003. Under this agreement, we receive a fee of $1.5 million per year for transportation on one of our NGL pipelines.

See Part I, Financial Information, Note 11 for a further discussion of our related party transactions.

Liquidity and Capital Resources

The ability to execute our growth strategy and complete our projects is dependent upon our access to the capital necessary to fund the projects and acquisitions. Our success with capital raising efforts, including the formation of joint ventures to share costs and risks, continues to be the critical factor which determines how much we actually spend. We believe our access to capital resources is sufficient to meet the demands of our current and future operating growth needs and, although we currently intend to make the forecasted expenditures discussed below, we may adjust the timing and amounts of projected expenditures as necessary to adapt to changes in the capital markets.

Capital Resources

As part of our previously announced strategy for 2003 to raise approximately $300 million through the issuance of common units and other equity, we have received net proceeds totaling $181.7 million through the issuance of approximately 5,718,881 common units since January 1, 2003 from the following offerings:

Offering Date	Common Units Issued	Public Offering Price	Net Offering Proceeds
		(per unit)	(in millions)
June 2003	1,150,000	$36.50	$ 40.3
May 2003	1,118,881	$35.75	$ 38.3
April 2003	3,450,000	$31.35	$103.1

We used the net proceeds from our common unit offerings to temporarily reduce amounts outstanding under our $600 million revolving credit facility and for general partnership purposes.

Series B Preference Units

In connection with our second quarter 2003 public offerings of common units, our general partner, in lieu of a cash contribution, contributed to us, and we retired, 1,378 Series B preference units with liquidation value of approximately $1.8 million, including accrued distributions of approximately $0.4 million, to maintain its one percent general partner interest.

Series F Convertible Units

In connection with our public offering of 1,118,881 common units in May 2003, we issued 80 Series F convertible units. Each Series F convertible unit is comprised of two separate detachable units — a Series F1 convertible unit and a Series F2 convertible unit — that have identical terms except for vesting and termination times and the number of underlying common units into which they may be converted. The Series F1 units are convertible into up to $80 million of common units anytime after August 12, 2003, and until March 29, 2004 (subject to defined extension rights). The Series F2 units are convertible into up to $40 million of common units provided at least $40 million of Series F1 convertible units are converted prior to their termination. The Series F2 units terminate on March 30, 2005 (subject to defined extension rights). The price at which the Series F convertible units may be converted to common units is equal to the lesser of the prevailing price (as defined below), if the prevailing price is equal to or greater than $35.75 or the prevailing price minus the product of 50 percent of the positive difference, if any, of $35.75 minus the prevailing price. The prevailing price is equal to the lesser of (i) the average closing price of our common units for the 60 business days ending on and including the fourth business day prior to our receiving notice from the holder of the Series F convertible units of their intent to convert them into common units; (ii) the average closing price of our common units for the first seven business days of the 60 day period included in (i); or (iii) the average closing price of our common units for the last seven days of the 60 day period included in (i). If they had been eligible for conversion, the price at which the Series F convertible units could have been converted to common units, based on the previous 60 business days at June 30, 2003 and August 7, 2003, was $29.67 and $36.15. The Series F units may be converted into a maximum of 8,329,679 common units and are not entitled to any dividends or distributions, nor do they have any voting rights prior to conversion. The value associated with the Series F convertible units is included in partners' capital as a component of common units.

The Series F convertible units have a feature which allows us to establish a minimum conversion unit price. Should the actual conversion unit price be below the minimum conversion unit price, we would be required to settle the conversion in cash in lieu of issuing common units. Currently, no minimum conversion unit price has been established; however, if a minimum conversion unit price is established, we may have to change our accounting treatment for the Series F convertible units to account for them as a derivative under the provisions of SFAS No. 133 and record an asset or liability for the fair value of the Series F convertible units and the changes in fair value would impact our earnings.

Forecasted Expenditures

We estimate our forecasted expenditures based upon our strategic operating and growth plans, which are also dependent upon our ability to produce or otherwise obtain the capital necessary to accomplish our operating and growth objectives. These estimates may change due to factors beyond our control, such as weather related issues, changes in supplier prices or poor economic conditions. Further, estimates may change as a result of decisions made at a later date, which may include acquisitions, scope changes or decisions to take on additional partners. Our projection of expenditures for the quarters ended June 30 and March 31, 2003 as presented in our 2002 Annual Report on Form 10-K, were $92 and $120 million; however, our actual expenditures were approximately $125 and $80 million.

The table below depicts our estimate of projects and capital maintenance expenditures through June 30, 2004 (in millions). These expenditures are net of anticipated project financings, contributions in aid of construction and contributions from joint venture partners, including the recently announced joint venture with Valero for the development of our Cameron Highway oil pipeline project and related project financing to fund a portion of the construction costs. We expect to be able to fund these forecasted expenditures from the combination of operating cash flow and funds available under our revolving credit facility and other financing arrangements. Actual results may vary from these projections.

	Quarters Ending				Net Total Forecasted Expenditures
	September 30, 2003	December 31, 2003	March 31, 2004	June 30, 2004	
			(In millions)		
Net Forecasted Capital Project Expenditures	$65	$70	$13	14	$162
Other Forecasted Capital Expenditures	12	8	18	13	51
Total Forecasted Expenditures	$77	$78	$31	$27	$213

Debt Repayment and Other Obligations

See Part I, Financial Information, Note 6, for a detailed discussion of our debt obligations.

The following table presents the timing and amounts of our debt repayment and other obligations for the years following June 30, 2003, that we believe could affect our liquidity (in millions):

Debt Repayment and Other Obligations	<1 Year	1-3 Years	3-5 Years	After 5 Years	Total
Revolving credit facility[1]	$ —	$ —	$415	$ —	$ 415
GulfTerra Holding term credit facility	—	160	—	—	160
Senior secured term loan	5	10	143	—	158
10 3/8% senior subordinated notes issued May 1999, due June 2009	—	—	—	175	175
8 1/2% senior subordinated notes issued March 2003, due June 2010	—	—	—	300	300
8 1/2% senior subordinated notes issued May 2001, due June 2011	—	—	—	250	250
8 1/2% senior subordinated notes issued May 2002, due June 2011	—	—	—	230	230
10 5/8% senior subordinated notes issued November 2002, due December 2012	—	—	—	200	200
Wilson natural gas storage facility operating lease	5	10	11	—	26
Total debt repayment and other obligations	$ 10	$180	$569	$1,155	$1,914

(1) Assumes the new maturity date for our revolving credit agreement is in 2006.

In March 2003, we issued $300 million in aggregate principal amount of 8 1/2% senior subordinated notes due June 2010. We used the proceeds of approximately $293 million, net of issuance costs, to repay $237.5 million of indebtedness under our senior secured acquisition term loan and to temporarily repay $55.5 million of the balance outstanding under our revolving credit facility.

Following our March 2003 repayment of the senior secured acquisition term loan, the amounts outstanding under our revolving credit facility bear interest, at our option, at either (i) 0.75% over the variable base rate (equal to the greater of the prime rate as determined by JPMorgan Chase Bank, the federal funds rate plus 0.5% or the Certificate of Deposit (CD) rate as determined by JPMorgan Chase Bank plus 1.00%); or (ii) 1.75% over LIBOR. For the GulfTerra Holding term credit facility, the amounts outstanding bear interest at 1% over the variable rate described above or LIBOR increased by 2.25%. Prior to our repayment of the senior secured acquisition term loan, the revolving credit facility and the GulfTerra Holding term credit facility both bore interest at 2.25% over the variable rate described above or LIBOR increased by 3.50%.

In July 2003, we issued $250 million in aggregate principal amount of our 6 1/4% senior notes due 2010. We used the proceeds of approximately $245.1 million, net of issuance costs, to repay the $160 million of indebtedness under the GulfTerra Holding term credit facility and the remaining $85.1 million to temporarily reduce amounts outstanding under our revolving credit facility.

In July 2003, Cameron Highway Oil Pipeline Company, our 50 percent owned joint venture that is constructing the 390-mile Cameron Highway Oil Pipeline, entered into a $325 million project loan facility consisting of a $225 million construction loan and $100 million of senior secured notes. See Part I, Financial Information, Note 6 for further discussion.

In July 2003, to achieve a better mix of fixed rate debt and variable rate debt, we entered into an eight-year interest rate swap agreement to provide for a floating interest rate on our fixed 8 1/2% $250 million senior subordinated notes that were issued in May 2001. With this swap agreement, we will pay the counterparty a LIBOR based interest rate plus a spread of 4.20% and receive a fixed rate of 8 1/2%. We are accounting for this derivative as a fair value hedge.

We are currently negotiating the renewal of our revolving credit facility to extend the maturity date beyond May 2004 on terms not more restrictive than our existing facility. We intend, and believe we have the ability, to renew this facility and have therefore reflected the outstanding balance as long term.

We expect to use the proceeds we receive from any additional capital we raise through the issuance of additional common units to reduce amounts outstanding under our credit facilities, to finance growth opportunities and for general partnership purposes. Our ability to raise additional capital may be negatively affected by many factors, including our relationship with El Paso Corporation.

Cash From Operating Activities

Net cash provided by operating activities was $134.2 million for the six months ended June 30, 2003, compared to $61.6 million for the same period in 2002. The increase was attributable to operating cash flows generated by our acquisitions of the EPN Holding assets in April 2002 and the San Juan assets in November 2002.

Cash Used In Investing Activities

Net cash used in investing activities was approximately $204.0 million for the six months ended June 30, 2003. Our investing activities include capital expenditures related to the construction of the Marco Polo pipelines, the Cameron Highway oil pipeline, and the Falcon Nest fixed-leg platform.

Cash From Financing Activities

Net cash provided by financing activities was approximately $51.4 million for the six months ended June 30, 2003. During 2003, our cash provided by financing activities included issuances of long-term debt and offerings of common units and convertible units. Cash used in our financing activities included repayments on our senior secured acquisition term loan, our revolving credit facility and other financing obligations, as well as distributions to our partners.

Acquisition

During the six months ended June 30, 2003, the total purchase price and net assets acquired for the April 2002 EPN Holding asset acquisition increased $17.5 million due to post-closing purchase price adjustments related primarily to natural gas imbalances assumed in the transaction. The following table summarizes our allocation of the fair values of the assets acquired and liabilities assumed. Our allocation among the assets acquired is based on the results of an independent third-party appraisal.

	At April 8, 2002
	(In thousands)
Current assets	$ 4,690
Property, plant and equipment	780,648
Intangible assets	3,500
Total assets acquired	788,838
Current liabilities	15,229
Environmental liabilities	21,136
Total liabilities assumed	36,365
Net assets acquired	$752,473

Construction Projects

We are currently constructing, among others, the following projects:

	Capital Expenditures				Capacity		
	Forecasted		As of June 30, 2003				
	Total[(1)]	GulfTerra[(2)]	Total[(1)]	GulfTerra[(2)]	Oil	Natural Gas	Expected Completion
	(In millions)				(MBbls/d)	(MMcf/d)	
Medusa Natural Gas Pipeline	$ 28	$ 26	$ 22	$ 22	—	160	Fourth Quarter 2003
Marco Polo							
Tension Leg Platform[(3)]	224	33	161	33	120	300	Fourth Quarter 2003
Natural Gas and Oil Pipelines	101	84	33	33	120	400	First Quarter 2004
Phoenix Gathering System	66	60	2	2	—	450	Second Quarter 2004
Cameron Highway Oil Pipeline[(4)]	458	85	99	99	500	—	Third Quarter 2004

(1) Includes 100% of costs and is not reduced for anticipated contributions in aid of construction, project financings and contributions from joint venture partners. We expect to receive from subsidiaries of El Paso Corporation the following: $2 million from Tennessee Gas Pipeline for our Medusa project, $7.0 million from El Paso Field Services for the Marco Polo pipeline and $6.1 million from ANR Pipeline Company for our Phoenix project. We have received $10.5 million from ANR Pipeline Company for the Marco Polo pipeline.

(2) GulfTerra expenditures are net of anticipated or received contributions in aid of construction, project financings and contributions from joint venture partners to the extent applicable.

(3) Forecasted expenditures increased during the first quarter of 2003 due to increases in gas processing capacity (from 250 to 300 MMcf/d) and oil processing capacity (from 100 to 120 MBbls/d) and a higher builder's risk insurance cost.

(4) In July 2003, we announced the completion of agreements to form a 50/50 joint venture with Valero Energy Corporation. Valero paid us approximately $51 million at closing representing 50 percent of the capital investment expended through that date.

Projects Announced in 2003

San Juan Optimization Project. In May 2003, we announced the approval of a $43 million project relating to our San Juan Basin assets. The project is expected to be completed in stages through 2006. The project is expected to result in a 130 MMcf/d increase in capacity, added compression to the Chaco processing facility and increased market opportunities through a new interconnect at the tailgate of the Chaco processing facility. As of June 30, 2003, we have spent approximately $0.6 million related to this project.

Other Matters

As a result of current circumstances generally surrounding the energy sector, the creditworthiness of several industry participants has been called into question, including El Paso Corporation, the indirect parent of our general partner. As a result of these general circumstances, we have established an internal group to monitor our exposure to, and determine, as appropriate, whether we should request prepayments, letters of credit or other collateral from our counterparties. During the second quarter of 2003, we received a letter of credit from Merchant Energy totaling $5.1 million regarding our existing customer/contractual relationships with them. If these general conditions worsen and, as a result, several industry participants file for Chapter 11 bankruptcy protection, it could have a material adverse effect on our financial position, results of operations or cash flows. While some industry participants have filed for Chapter 11 bankruptcy protection during the past six months, our exposure to these participants has not been significant. However, based upon our review of the collectibility of accounts receivable, we increased our allowance by $2.0 million during the second quarter of 2003. As of June 30, 2003 and December 31, 2002, our allowance was $4.5 million and $2.5 million.

Results of Operations

Our business activities are segregated into four distinct operating segments:

- Natural gas pipelines and plants;
- Oil and NGL logistics;
- Natural gas storage; and
- Platform services.

As a result of our sale of the Prince TLP and our nine percent overriding interest in the Prince Field in April 2002, the results of operations from these assets are reflected as discontinued operations in our statements of income for all periods presented and are not reflected in our segment results below.

To the extent possible, results of operations have been reclassified to conform to the current business segment presentation, although these results may not be indicative of the results which would have been achieved had the revised business segment structure been in effect during those periods. Operating revenues and expenses by segment include intersegment revenues and expenses which are eliminated in consolidation. For a further discussion of the individual segments, see Part I, Financial Information, Note 9.

We use earnings before interest, income taxes, depreciation and amortization (EBITDA) to assess our consolidated and segment results. EBITDA is our liquidity measure as our lenders are interested in whether we generate sufficient cash to meet our debt obligations as they become due. Accordingly, our revolving credit agreement and indentures utilize EBITDA to represent a measure of the cash flows from current operations. Our equity investors generally focus on our capacity to pay distributions or to grow the business, or both. As a result, our ability to generate cash from operations of the business to cover distributions, debt service, as well as to pursue growth opportunities, is an important measure of our liquidity. A reconciliation of this measure to cash flows from operations for our consolidated results is as follows:

	Quarter Ended June 30,		Six Months Ended June 30,	
	2003	2002	2003	2002
Cash Flow from Operations	$ 62,722	$18,394	$134,166	$ 61,601
Plus: Interest expense	31,838	21,534	66,324	33,292
Working capital changes, net of effects of acquisitions and noncash transactions	10,592	28,913	14,665	20,514
Gain (loss) on sale of long-lived assets	(363)	—	(257)	315
Net cash payment received from El Paso Corporation	2,078	1,917	4,118	3,799
Discontinued operations of Prince facilities	—	59	—	6,508
Less: Net cash provided by discontinued operations	—	(392)	—	5,037
Noncash items on cash flow statement	(1,725)	230	4,520	1,495
EBITDA	$108,592	$70,979	$214,496	$119,497

Segment Results

The following table presents EBITDA by segment and in total.

	Quarter Ended June 30, 2003	Quarter Ended June 30, 2002	Six Months Ended June 30, 2003	Six Months Ended June 30, 2002
	(In thousands)			
Natural gas pipelines and plants	$ 78,339	$47,114	$156,141	$ 67,292
Oil and NGL logistics	12,897	12,069	24,497	22,784
Natural gas storage	8,068	2,091	15,069	4,800
Platform services	6,277	7,493	10,512	20,315
Segment EBITDA	105,581	68,767	206,219	115,191
Other, net	3,011	2,212	8,277	4,306
Consolidated EBITDA	$108,592	$70,979	$214,496	$119,497

See Item 1, Financial Information, Note 9 for a reconciliation of segment EBITDA to net income.

Natural Gas Pipelines and Plants

	Quarter Ended June 30, 2003	Quarter Ended June 30, 2002	Six Months Ended June 30, 2003	Six Months Ended June 30, 2002
	(In thousands, except for volumes)			
Natural gas pipelines and plants revenue	$199,547	$ 95,253	$ 396,774	$135,672
Cost of natural gas	(86,123)	(27,343)	(175,919)	(39,501)
Natural gas pipelines and plants margin	113,424	67,910	220,855	96,171
Operating expenses excluding depreciation, depletion, and amortization	(36,123)	(20,806)	(66,569)	(28,892)
Other income	664	10	1,360	13
Cash distributions from unconsolidated affiliates in excess of earnings[1]	374	—	495	—
EBITDA	$ 78,339	$ 47,114	$ 156,141	$ 67,292

[1] Earnings from unconsolidated affiliates for the quarter and six months ended June 30, 2003, was $626 thousand and $1,255 thousand.

	Quarter Ended June 30, 2003	Quarter Ended June 30, 2002	Six Months Ended June 30, 2003	Six Months Ended June 30, 2002
	(In thousands, except for volumes)			
Volumes (MDth/d)				
Texas Intrastate	3,407	3,440	3,380	1,730
San Juan gathering	1,241	—	1,186	—
Permian gathering	349	351	334	195
HIOS	707	724	729	777
Viosca Knoll gathering	672	591	680	562
Other natural gas pipelines	667	361	607	385
Processing plants	781	787	796	703
Total volumes	7,824	6,254	7,712	4,352

Transportation agreements with some of our customers require that we purchase natural gas from producers at the wellhead for an index price less an amount that compensates us for gathering services. We then sell the natural gas into the open market at points on our system at the same index price. Accordingly, our operating revenues and costs of natural gas are impacted by changes in energy commodity prices, while our margin is unaffected by these contracts. For these reasons, we believe that gross margin (revenue less cost of natural gas) provides a more accurate and meaningful basis than operating revenue or cost of natural gas for analyzing operating results for this segment.

Second Quarter Ended June 30, 2003 Compared With Second Quarter Ended June 30, 2002

Natural gas pipelines and plants margin for the quarter ended June 30, 2003, was $45.5 million higher than in the same period in 2002. Our San Juan Basin assets, acquired in November 2002, accounted for approximately $42.5 million of the increase. Margin also increased by approximately $2.3 million due to an increase in volumes attributable to a full quarter of results from our Falcon Nest Pipeline, which was placed in service in March 2003 and additional volumes on our Viosca Knoll system from the Canyon Express pipeline system. Additionally, margin increased by $2.0 million due to higher NGL prices in 2003, which favorably impacted our processing margins in the Permian Basin region. Partially offsetting these increases was a $3.2 million decrease in margin for our Texas intrastate pipeline attributable to the impact that higher natural gas prices in 2003 had on our fuel costs and the revaluation of our natural gas imbalances.

Operating expenses excluding depreciation, depletion, and amortization for the quarter ended June 30, 2003, were $15.3 million higher than the same period in 2002 primarily due to the acquisition of the San Juan Basin assets. Excluding the operating costs of these acquired assets, operating expenses increased by $9.5 million primarily due to an increase in our allowance for doubtful accounts of $2.0 million, higher repair and maintenance expenses of $3.1 million on our Texas intrastate pipeline, which were unusually low in the prior year quarter due to timing of expenditures, and a $3.6 million increase associated with our general and administrative services agreement with subsidiaries of El Paso Corporation. This increase is a result of our acquisitions in 2002.

Six Months Ended June 30, 2003 Compared With Six Months Ended June 30, 2002

Natural gas pipelines and plants margin for the six months ended June 30, 2003, was $124.7 million higher than in the same period in 2002. Our San Juan Basin assets, acquired in November 2002, and our EPN Holding assets, acquired in April 2002, accounted for approximately $85.4 million and $36.6 million of the increase. Additionally, margin increased by $1.7 million due to a full quarter of results from our Falcon Nest Pipeline which was placed in service in March 2003. Margin also increased by $2.0 million due to higher NGL prices in 2003, which favorably impacted our processing margins in the Permian Basin region and by approximately $2.5 million due to increased volumes on our Viosca Knoll system from the Canyon Express pipeline system, which was placed into service in September 2002. Offsetting these increases were a $3.2 million decrease in margin for our Texas intrastate pipeline system attributable to the impact that higher natural gas prices in 2003 had on our fuel costs and the revaluation of our natural gas imbalances and $2.2 million of decreased production on HIOS due to natural decline in the offshore region.

Operating expenses excluding depreciation, depletion, and amortization for the six months ended June 30, 2003, were $37.7 million higher than the same period in 2002 primarily due to the acquisitions of the San Juan Basin and EPN Holding assets. Excluding the operating costs of these acquired assets, operating expenses increased by $18.0 million primarily due to an increase in our allowance for doubtful accounts of $2.0 million, higher repair and maintenance expenses of $3.1 million on our Texas intrastate pipeline, which were unusually low in 2002 due to timing of expenditures, and a $10.2 million increase associated with our general and administrative services agreement with subsidiaries of El Paso Corporation. This increase is a result of our acquisitions in 2002.

Oil and NGL Logistics

	Quarter Ended June 30,		Six Months Ended June 30,	
	2003	2002	2003	2002
	(In thousands, except for volumes)			
Oil and NGL logistics revenues	$ 89,087	$ 9,750	$ 149,886	$ 18,576
Cost of oil	(73,181)	—	(122,012)	—
Oil and NGL logistics margin	15,906	9,750	27,874	18,576
Operating expenses excluding depreciation, depletion, and amortization	(5,531)	(2,361)	(9,861)	(4,972)
Other income	2,363	4,012	5,052	7,373
Cash distributions from unconsolidated affiliates in excess of earnings[(1)]	159	668	1,432	1,807
EBITDA	$ 12,897	$ 12,069	$ 24,497	$ 22,784
Volume (Bbl/d)				
Texas NGL System	58,770	76,067	62,880	73,466
Allegheny Oil Pipeline	14,053	17,096	15,763	17,658
Typhoon Oil Pipeline	31,238	—	24,913	—
Unconsolidated affiliate				
Poseidon Oil Pipeline[(2)]	134,751	147,021	144,222	144,861
Total volumes	238,812	240,184	247,778	235,985

(1) Earnings from unconsolidated affiliates for the quarter and six months ended June 30, 2003, was $2,361 thousand and $5,048 thousand. Earnings from unconsolidated affiliates for the quarter and six months ended June 30, 2002, was $4,012 thousand and $7,373 thousand.

(2) Represents 100% of the volumes flowing through the pipeline.

Transportation agreements with some of our customers require that we purchase the oil produced at the inlet of our pipeline for an index price less an amount that compensates us for transportation services. At the outlet of our pipeline, we resell this oil back to these producers at the same index price. We reflect these sales in gathering and processing revenues and the related purchases as cost of oil. For these reasons, we believe that gross margin (revenue less cost of oil) provides a more accurate and meaningful basis than operating revenue or cost of oil for analyzing operating results for this segment.

Second Quarter Ended June 30, 2003 Compared With Second Quarter Ended June 30, 2002

For the quarter ended June 30, 2003, margin was $6.2 million higher than the same period in 2002. Our Texas NGL assets and Typhoon Oil Pipeline, acquired in November 2002, contributed approximately $8.2 million to the increase. Partially offsetting this increase was a $1.7 million decline in margin for our transportation and fractionation assets. Our fractionation volumes decreased due to weak demand for NGLs and poor processing economics that reduced the amount of NGLs that were recovered at the natural gas processing plants connected to our NGL fractionation assets. The poor processing economics are largely driven by higher natural gas prices relative to NGL prices in 2003.

Operating expenses excluding depreciation, depletion, and amortization for the quarter ended June 30, 2003, were $3.2 million higher than the same period in 2002 primarily due to our November 2002 acquisition of the Typhoon Oil Pipeline and the Texas NGL assets.

Other income for the quarter ended June 30, 2003, was $1.6 million lower than the same period in 2002 due to a decrease in cash distributions from our unconsolidated affiliate Poseidon Oil Pipeline Company. Poseidon Oil Pipeline Company experienced lower earnings due to natural production declines on some of the older deepwater fields, as well as production downtime at several new fields.

Six Months Ended June 30, 2003 Compared With Six Months Ended June 30, 2002

For the six months ended June 30, 2003, margin was $9.3 million higher than the same period in 2002. Our Texas NGL assets and Typhoon Oil Pipeline, acquired in November 2002, contributed approximately $11.1 million to the increase. Partially offsetting this increase was a $1.9 million decline in margin for our transportation and fractionation assets. Our fractionation volumes decreased due to weak demand for NGL and poor processing economics that reduced the amount of NGL that were recovered at the natural gas processing plants connected to our NGL fractionation assets. The poor processing economics are largely driven by higher natural gas prices relative to NGL prices in 2003.

Operating expenses excluding depreciation, depletion, and amortization for the six months ended June 30, 2003 were $4.9 million higher than the same period in 2002, primarily due to our November 2002 acquisition of the Typhoon Oil Pipeline and the Texas NGL assets.

Other income for the six months ended June 30, 2003, was $2.3 million lower than the same period in 2002 due to a decrease in cash distributions from our unconsolidated affiliate Poseidon Oil Pipeline Company. Poseidon Oil Pipeline Company experienced lower earnings due to natural production declines on some of the older deepwater fields, as well as production downtime at several new fields.

Natural Gas Storage

	Quarter Ended June 30,		Six Months Ended June 30,	
	2003	2002	2003	2002
	(In thousands, except for volumes)			
Natural gas storage revenue	$11,057	$ 5,467	$22,755	$ 9,855
Cost of natural gas	132	—	(1,429)	—
Natural gas storage margin	11,189	5,467	21,326	9,855
Operating expenses excluding depreciation, depletion, and amortization	(3,121)	(3,376)	(6,257)	(5,055)
EBITDA	$ 8,068	$ 2,091	$15,069	$ 4,800
Firm storage				
Average working gas capacity available (Bcf)	13.5	7.2	13.5	7.2
Average firm subscription (Bcf)	12.7	6.7	12.7	7.2
Commodity volumes(1) (Bcf)	4.7	3.5	4.8	3.5
Interruptible storage				
Contracted volumes (Bcf)	0.4	0.4	0.2	0.3
Commodity volumes(1) (Bcf)	0.2	0.4	0.2	0.1

(1) Combined injections and withdrawals volumes.

We collect fixed and variable fees for providing storage services, some of which is generated from customers with cashout provisions, at a tariff-based index calculation. We incur expenses as we maintain these volumetric imbalance receivables and payables which are valued at current gas prices. For these reasons, we believe that gross margin (storage revenues less storage expenses) provides a more accurate and meaningful basis for analyzing operating results for the natural gas storage segment. Cost of natural gas reflects the initial loss of base gas in our storage facilities or the encroachment on our base gas by third parties at the market price in the period of the loss or encroachment and the monthly revaluation of these amounts based on the monthly change in natural gas prices.

Second Quarter Ended June 30, 2003 Compared With Second Quarter Ended June 30, 2002

For the quarter ended June 30, 2003, margin was $5.7 million higher than the same period in 2002 primarily due to an increase in subscribed firm storage capacity attributable to the expansion of the Petal storage facility, which was completed in June 2002.

Six Months Ended June 30, 2003 Compared With Six Months Ended June 30, 2002

For the six months ended June 30, 2003, margin was $11.5 million higher than the same period in 2002 primarily due to an increase in subscribed firm storage capacity attributable to the expansion of the Petal storage facility, which was completed in June 2002, and our acquisition of the Wilson storage facility lease in April 2002.

Operating expenses excluding, depreciation, depletion, and amortization for the six months ended June 30, 2003 were $1.2 million higher than the same period in 2002 primarily due to the acquisition of the Wilson storage facility lease in April 2002.

Platform Services

	Quarter Ended June 30,		Six Months Ended June 30,	
	2003	**2002**	**2003**	**2002**
	(In thousands, except for volumes)			
Platform services revenue from external customers	$ 6,101	$5,165	$10,483	$ 9,627
Platform services intersegment revenue	758	3,114	1,404	6,223
Operating expenses excluding depreciation, depletion, and amortization	(582)	(845)	(1,375)	(1,231)
Discontinued operations of Prince facilities	—	59	—	5,696
EBITDA	$ 6,277	$7,493	$10,512	$20,315
Natural gas platform volumes (Mdth/d)				
East Cameron 373 platform	104	134	112	142
Garden Banks 72 platform	20	22	23	14
Viosca Knoll 817 platform	5	9	6	9
Falcon Nest platform	190	—	110	—
Total natural gas platform volumes	319	165	251	165
Oil platform volumes (Bbl/d)				
East Cameron 373 platform	920	1,989	871	1,859
Garden Banks 72 platform	1,102	1,295	1,067	1,179
Viosca Knoll 817 platform	2,020	2,072	2,005	2,073
Falcon Nest platform	720	—	422	—
Total oil platform volumes	4,762	5,356	4,365	5,111

Second Quarter Ended June 30, 2003 Compared With Second Quarter Ended June 30, 2002

For the quarter ended June 30, 2003, revenues from external customers were $0.9 million higher than in the same period in 2002, of which $3.2 million is attributable to the Falcon Nest fixed leg platform that went into operation in March 2003. This increase is partially offset by lower revenues of $2.2 million from East Cameron 373 resulting from lower demand fees and lower production. Intersegment revenues were $2.4 million lower due to a decline in the fixed portion of our platform access fees on the Viosca Knoll 817 and Garden Banks 72 platforms associated with contracts with one of our wholly owned subsidiaries, which terms expired in June 2002 and December 2002. Operating expenses for the same periods were $0.3 million lower due to lower operating and allocation expense.

Six Months Ended June 30, 2003 Compared With Six Months Ended June 30, 2002

For the six months ended June 30, 2003, revenues from external customers were $0.9 million higher than in the same period in 2002, of which $3.8 million is attributable to the Falcon Nest fixed leg platform that went into operation in March 2003. This increase is partially offset by lower revenues of $2.8 million from East Cameron 373 resulting from one time billing adjustments in 2002 for fixed monthly platform access fees, a gas dehydration fee, decreased demand fees and lower production. Intersegment revenues were $4.8 million lower due to a decline in the fixed portion of our platform access fees on the Viosca Knoll 817 and Garden Banks 72 platforms associated with contracts with one of our wholly owned subsidiaries, which terms expired in June 2002 and December 2002.

Other, Net

Second Quarter Ended June 30, 2003 Compared With Second Quarter Ended June 30, 2002

EBITDA related to non-segment activity for the quarter ended June 30, 2003, was $0.8 million higher than the same period in 2002 due to lower platform access fee expense as a result of the expiration in June 2002 of the fixed fee portion of the Viosca Knoll 817 platform access fee contract and the Garden Banks 72 platform access fee contract in December 2002. Partially offsetting this increase was higher operating expenses associated with an increase in professional services.

Six Months Ended June 30, 2003 Compared With Six Months Ended June 30, 2002

EBITDA related to non-segment activity for the six months ended June 30, 2003, was $4.0 million higher than in the same period in 2002 due to lower platform access fee expense as a result of the expiration of the fixed fee portion of the Viosca Knoll 817 platform access fee contract in June 2002 and the Garden Banks 72 platform access fee contract in December 2002. Partially offsetting this increase was higher operating expenses associated with an increase in professional services.

Depreciation, Depletion, and Amortization

Depreciation, depletion, and amortization for the quarter and six months ended June 30, 2003, was $6.7 million and $17.9 million higher than the same periods in 2002. This increase is primarily due to our November 2002 acquisition of the San Juan assets and our April 2002 acquisition of the EPN Holding assets. Further contributing to the increase was the completion of the Falcon Nest platform in March 2003 and the Petal expansion in June 2002.

Interest and Debt Expense

Interest and debt expense, net of capitalized interest, for the quarter and six months ended June 30, 2003, was approximately $10.3 million and $33.0 million higher than the same periods in 2002. This increase for the six month period is primarily due to a higher weighted average interest rate, increase in capitalized interest, a higher outstanding balance on our revolving credit facility and increased interest incurred on the following indebtedness:

- the GulfTerra Holding term credit facility which we entered in connection with our acquisition of the EPN Holding assets in April 2002;
- our $230 million 8½% senior subordinated notes which we issued in May 2002 and used to repay a portion of the GulfTerra Holding term credit facility;
- our $160 million senior secured term loan which we entered in October 2002;
- our $200 million 10⅝% senior subordinated notes we issued and our $237.5 million senior secured acquisition term loan we entered in November 2002 in connection with our acquisition of the San Juan assets; and
- our $300 million 8½% senior subordinated notes which we issued in March 2003 and used to repay our $237.5 million senior secured acquisition term loan.

The increase in interest expense for the quarter ended June 30, 2003 compared to the same period in 2002 is attributable to the interest incurred on the additional indebtedness discussed above, partially offset by lower weighted average interest rates and lower outstanding balances on our revolving credit facility and the GulfTerra Holding term credit facility and an increase in capitalized interest.

Capitalized interest for the quarter and six months ended June 30, 2003 was $2.6 million and $4.5 million, representing increases of $0.6 million and $0.9 million over the comparable prior periods. The increases are the result of an increase in construction work-in-process as a result of increased expenditures related to our construction projects.

Loss Due to Write-off of Debt Issuance Cost

In March 2003, we repaid our $237.5 million senior secured term loan which was due in May 2004 and recognized a loss of $3.8 million related to the write-off of the unamortized debt issuance costs related to this loan.

Commitments and Contingencies

See Item 1, Financial Information, Note 7, which is incorporated herein by reference.

New Accounting Pronouncements Not Yet Adopted

See Item 1, Financial Information, Note 13, which is incorporated by reference.

CAUTIONARY STATEMENT REGARDING FORWARD-LOOKING STATEMENTS

We have made statements in this document that constitute forward-looking statements. These statements are subject to risks and uncertainties. Forward-looking statements include information concerning possible or assumed future results of operations. These statements may relate to information or assumptions about:

- earnings per unit;
- capital and other expenditures;
- cash distributions;
- financing plans;
- capital structure;
- liquidity and cash flow;
- pending legal proceedings and claims, including environmental matters;
- future economic performance;
- operating income;
- cost savings;
- management's plans; and
- goals and objectives for future operations.

Important factors that could cause actual results to differ materially from estimates or projections contained in forward-looking statements are described in our Annual Report on Form 10-K for the year ended December 31, 2002, and our other filings with the Securities and Exchange Commission. Where any forward-looking statement includes a statement of the assumptions or bases underlying the forward-looking statement, we caution that, while we believe these assumptions or bases to be reasonable and made in good faith, assumed facts or bases almost always vary from the actual results, and the differences between assumed facts or bases and actual results can be material, depending upon the circumstances. Where, in any forward-looking statement, we express an expectation or belief as to future results, such expectation or belief is expressed in good faith and is believed to have a reasonable basis. We cannot assure you, however, that the statement of expectation or belief will result or be achieved or accomplished. These statements relate to analyses and other information which are based on forecasts of future results and estimates of amounts not yet determinable. These statements also relate to our future prospects, developments and business strategies. These forward-looking statements are identified by their use of terms and phrases such as "anticipate," "believe," "could," "estimate," "expect," "intend," "may," "plan," "predict," "project," "will," and similar terms and phrases, including references to assumptions. These forward-looking statements involve risks and uncertainties that may cause our actual future activities and results of operations to be materially different from those suggested or described.

These risks may also be specifically described in our Current Reports on Form 8-K and other documents filed with the Securities and Exchange Commission. We undertake no obligation to publicly update or revise any forward-looking statements, whether as a result of new information or otherwise. If one or more of these risks or uncertainties materialize, or if underlying assumptions prove incorrect, our actual results may vary materially from those expected, estimated or projected.

Item 3. Quantitative and Qualitative Disclosures About Market Risk

This information updates, and you should read it in conjunction with, our quantitative and qualitative disclosures about market risks reported in our Annual Report on Form 10-K for the year ended December 31, 2002, in addition to information presented in Items 1 and 2 of this Quarterly Report on Form 10-Q.

In August 2002, we entered into a derivative financial instrument to hedge our exposure during 2003 to changes in natural gas prices relating to gathering activities in the San Juan Basin in anticipation of our acquisition of the San Juan assets. The derivative is a financial swap on 30,000 MMBtu per day whereby we receive a fixed price of $3.525 per MMBtu and pay a floating price based on the San Juan index. Beginning with the acquisition date in November 2002, we are accounting for this derivative as a cash flow hedge under SFAS No. 133. In February 2003, we entered into an additional derivative financial instrument to continue to hedge our exposure during 2004 to changes in natural gas prices relating to gathering activities in the San Juan Basin. The derivative is a financial swap on 15,000 MMBtu per day whereby we receive a fixed price of $3.95 per MMBtu and pay a floating price based on the San Juan index. We are accounting for this derivative as a cash flow hedge under SFAS No. 133. As of June 30, 2003, the fair value of these cash flow hedges was a liability of $10.3 million. For the six months ended June 30, 2003, we reclassified a loss of $6.0 million from accumulated other comprehensive income resulting in a reduction to earnings. No ineffectiveness exists in this hedging relationship because all purchase and sale prices are based on the same index and volumes as the hedge transaction. We estimate the entire amount will be classified from accumulated other comprehensive income as a reduction to earnings over the next 18 months and approximately $9.7 million will be reclassed as a reduction to earnings over the next twelve months.

Prior to June 30, 2003, in connection with our GulfTerra Intrastate Alabama operations, we had fixed price contracts with specific customers for the sale of predetermined volumes of natural gas for delivery over established periods of time. We entered into cash flow hedges in 2002 and 2003 to offset the risk of increasing natural gas prices. As of June 30, 2003, these cash flow hedges expired and we reclassified a gain of $0.2 million from accumulated other comprehensive income to earnings. No ineffectiveness existed in this hedging relationship because all purchase and sale prices were based on the same index and volumes as the hedge transaction.

In January 2002, Poseidon entered into a two-year interest rate swap agreement to fix the variable portion of its LIBOR based interest rate on $75 million of its $185 million variable rate revolving credit facility at 3.49% over the life of the swap. Prior to April 2003, under its credit facility, Poseidon paid an additional 1.50% over the LIBOR rate resulting in an effective interest rate of 4.99% on the hedged notional amount. Beginning in April 2003, the additional interest Poseidon pays over LIBOR was reduced to 1.25% resulting in an effective fixed interest rate of 4.74% on the hedged notional amount. As of June 30, 2003, the fair value of its interest rate swap was a liability of $0.9 million resulting in accumulated other comprehensive loss of $0.9 million. We included our 36 percent share of this liability of $0.3 million as a reduction of our investment in Poseidon and as loss in accumulated other comprehensive income which we estimate will be reclassified to earnings proportionately over the next six months. Additionally, we have recognized in income our 36 percent share of Poseidon's realized loss of $0.7 million for the six months ended June 30, 2003, or $0.2 million, through our earnings from unconsolidated affiliates.

In July 2003, to achieve a better mix of fixed rate debt and variable rate debt, we entered into an eight-year interest rate swap agreement to provide for a floating interest rate on our fixed 8½% $250 million senior subordinated notes that were issued in May 2001. With this swap agreement, we will pay the counterparty a LIBOR based interest rate plus a spread of 4.20% and receive a fixed rate of 8½%. We are accounting for this derivative as a fair value hedge.

Item 4. Controls and Procedures

Evaluation of Controls and Procedures. Under the supervision and with the participation of management, including our principal executive officer and principal financial officer, we have evaluated the effectiveness of the design and operation of our disclosure controls and procedures (Disclosure Controls) and internal controls over financial reporting (Internal Controls) as of the end of the period covered by this Quarterly Report pursuant to Rules 13a-15 and 15d-15 under the Securities Exchange Act of 1934 (Exchange Act).

Definition of Disclosure Controls and Internal Controls. Disclosure Controls are our controls and other procedures that are designed to ensure that information required to be disclosed by us in the reports that we file or submit under the Exchange Act is recorded, processed, summarized and reported, within the time periods specified under the Exchange Act. Disclosure Controls include, without limitation, controls and procedures designed to ensure that information required to be disclosed by us in the reports that we file under the Exchange Act is accumulated and communicated to our management, including our principal executive officer and principal financial officer, as appropriate to allow timely decisions regarding required disclosure. Internal Controls are procedures which are designed with the objective of providing reasonable assurance that (1) our transactions are properly authorized; (2) our assets are safeguarded against unauthorized or improper use; and (3) our transactions are properly recorded and reported, all to permit the preparation of our financial statements in conformity with generally accepted accounting principles.

Limitations on the Effectiveness of Controls. Our management, including the principal executive officer and principal financial officer, does not expect that our Disclosure Controls and Internal Controls will prevent all errors and all fraud. The design of a control system must reflect the fact that there are resource constraints, and the benefits of controls must be considered relative to their costs. Because of the inherent limitations in all control systems, no evaluation of controls can provide absolute assurance that all control issues and instances of fraud, if any, within the company have been detected. These inherent limitations include the realities that judgments in decision-making can be faulty, and that breakdowns can occur because of simple errors or mistakes. Additionally, controls can be circumvented by the individual acts of some persons, by collusion of two or more people, or by management override of the controls. The design of any system of controls also is based in part upon certain assumptions about the likelihood of future events. Therefore, a control system, no matter how well conceived and operated, can provide only reasonable, not absolute, assurance that the objectives of the control system are met. Our Disclosure Controls and Internal Controls are designed to provide such reasonable assurances of achieving our desired control objectives, and our principal executive officer and principal financial officer have concluded that our Disclosure Controls and Internal Controls are effective in achieving that level of reasonable assurance.

No Significant Changes in Internal Controls. We have sought to determine whether there were any "significant deficiencies" or "material weaknesses" in GulfTerra Energy Partners' Internal Controls, or whether GulfTerra Energy Partners had identified any acts of fraud involving personnel who have a significant role in GulfTerra Energy Partners' Internal Controls. This information was important both for the controls evaluation generally and because the principal executive officer and principal financial officer are required to disclose that information to our Board's Audit Committee and our independent auditors and to report on related matters in this section of the Quarterly Report. The principal executive officer and principal financial officer note that there have not been any significant changes in Internal Controls or in other factors that could significantly affect Internal Controls, including any corrective actions with regard to significant deficiencies and material weaknesses.

Effectiveness of Disclosure Controls. Based on the controls evaluation, our principal executive officer and principal financial officer have concluded that the Disclosure Controls are effective to ensure that material information relating to GulfTerra Energy Partners and its consolidated subsidiaries is made known to management, including the principal executive officer and principal financial officer, on a timely basis.

Officer Certifications. The certifications from the principal executive officer and principal financial officer required under Sections 302 and 906 of the Sarbanes-Oxley Act of 2002 have been included as Exhibits to this Quarterly Report.

PART II — OTHER INFORMATION

Item 1. Legal Proceedings

See Part I, Financial Information, Note 7, which is incorporated herein by reference.

Item 2. Changes in Securities and Use of Proceeds

We have amended our partnership agreement, and issued a new series of convertible units, both of which affect our common units. See Part I, Item 2, Management's Discussion and Analysis, "General Partner Relationship" and "Liquidity and Capital Resource" for discussions of how these changes affect our common units, which is incorporated herein by reference.

Item 3. Defaults Upon Senior Securities

None.

Item 4. Submission of Matters to a Vote of Security Holders

None.

Item 5. Other Information

In May 2003, we announced that effective May 6, 2003, W. Matt Ralls, senior vice president and chief financial officer of GlobalSantaFe Corporation, was elected to join our board of directors.

Mr. Ralls, 54, is senior vice president and chief financial officer of GlobalSantaFe, one of the largest international drilling contractors, providing offshore and land drilling services to the world's leading oil and gas companies. From 1997 to 2001, he was Global Marine's vice president, chief financial officer and treasurer. Previously, he served as executive vice president, chief financial officer and a director of Kelley Oil and Gas Corporation and as vice president of Capital Markets and Corporate Development for The Meridian Resource Corporation before joining Global Marine. He spent the first 17 years of this career in commercial banking at the senior loan management level. Mr. Ralls received an MBA from the University of Texas at Austin.

Item 6. Exhibits and Reports on Form 8-K

(a) Exhibits

Each exhibit identified below is filed as part of this document. Exhibits not incorporated by reference to a prior filing are designated by a "*"; all exhibits not so designated are incorporated herein by reference to a prior filing as indicated. Exhibits designated with a "+" represent a management contract or compensatory plan or arrangement.

Exhibit Number		Description
3.A	—	Amended and Restated Certificate of Limited Partnership dated February 14, 2002; Amendment dated April 30, 2003, to Certificate of Limited Partnership.
*3.A.1	—	Amendment 2 dated July 25, 2003, to the Amended and Restated Certificate of Limited Partnership.
3.B	—	Second Amended and Restated Agreement of Limited Partnership effective as of August 31, 2000 (Exhibit 3.B to our Current Report on Form 8-K dated March 6, 2001); First Amendment dated November 27, 2002 (Exhibit 3.B.1 to our Current Report on Form 8-K dated December 11, 2002); Second Amendment dated May 5, 2003 (Exhibit 3.B.2 to our Current Report on Form 8-K dated May 13, 2003); Third Amendment dated May 16, 2003 (Exhibit 3.B.3 to our Current Report 8-K dated May 16, 2003).

Exhibit Number	Description
*3.B.1	— Fourth Amendment dated July 23, 2003, to the Second Amended and Restated Agreement of Limited Partnership.
4.D	— Indenture dated as of May 27, 1999 among GulfTerra Energy Partners, L.P., GulfTerra Energy Finance Corporation, the Subsidiary Guarantors and Chase Bank of Texas, as Trustee (Exhibit 4.1 to our Registration Statement on Form S-4, filed on June 24, 1999, File Nos. 333-81143 through 333-81143-17); First Supplemental Indenture dated as of June 30, 1999 (Exhibit 4.2 to our Amendment No. 1 to Registration Statement on Form S-4, filed August 27, 1999 File Nos. 333-81143 through 333-81143-17); Second Supplemental Indenture dated as of July 27, 1999 (Exhibit 4.3 to our Amendment No. 1 to Registration Statement on Form S-4, filed August 27, 1999, File Nos. 333-81143 through 333-81143-17); Third Supplemental Indenture dated as of March 21, 2000, to the Indenture dated as of May 27, 1999, (Exhibit 4.7.1 to our 2000 Second Quarter Form 10-Q); Fourth Supplemental Indenture dated as of July 11, 2000 (Exhibit 4.2.1 to our 2001 Third Quarter Form 10-Q); Fifth Supplemental Indenture dated as of August 30, 2000 (Exhibit 4.2.2 to our 2001 Third Quarter Form 10-Q); Sixth Supplemental Indenture dated as of April 18, 2002 (Exhibit 4.D.1 to our 2002 First Quarter Form 10-Q); Seventh Supplemental Indenture dated as of April 18, 2002 (Exhibit 4.D.2 to our 2002 First Quarter Form 10-Q); Eighth Supplemental Indenture dated as of October 10, 2002 (Exhibit 4.D.3 to our 2002 Third Quarter Form 10-Q); Ninth Supplemental Indenture dated as of November 27, 2002 (Exhibit 4.D.1 to our Current Report on Form 8-K dated March 19, 2003); Tenth Supplemental Indenture dated as of January 1, 2003 (Exhibit 4.D.2 to our Current Report on Form 8-K dated March 19, 2003).
*4.D.1	— Eleventh Supplemental Indenture dated as of June 20, 2003, to the Indenture dated as of May 27, 1999 among GulfTerra Energy Partners, L.P., GulfTerra Energy Finance Corporation, the Subsidiary Guarantors named therein and JPMorgan Chase Bank, as Trustee.
4.E	— Indenture dated as of May 17, 2001 among GulfTerra Energy Partners, L.P., GulfTerra Energy Finance Corporation, The Subsidiary Guarantors named therein and the Chase Manhattan Bank, as Trustee (Exhibit 4.1 to our Registration Statement on Form S-4 filed June 25, 2001, Registration Nos. 333-63800 through 333-63800-20); First Supplemental Indenture dated as of April 18, 2002 (Exhibit 4.E.1 to our 2002 First Quarter Form 10-Q), Second Supplemental Indenture dated as of April 18, 2002 (Exhibit 4.E.2 to our 2002 First Quarter Form 10-Q); Third Supplemental Indenture dated as of October 10, 2002 (Exhibit 4.E.3 to our 2002 Third Quarter Form 10-Q); Fourth Supplemental Indenture dated as of November 27, 2002 (Exhibit 4.E.1 to our Current Report on Form 8-K dated March 19, 2003); Fifth Supplemental Indenture dated as of January 1, 2003 (Exhibit 4.E.2 to our Current Report on Form 8-K dated March 19, 2003).
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4.F	— Letter agreement dated March 5, 2002, between Crystal Gas Storage, Inc. and GulfTerra Energy Partners, L.P. (Exhibit 4.F of our 2001 Form 10-K).

Exhibit Number	Description
4.G	— Registration Rights Agreement by and between El Paso Corporation and GulfTerra Energy Partners, L.P. dated as of November 27, 2002 (Exhibit 4.G to our Current Report on Form 8-K dated December 11, 2002).
4.I	— Indenture dated as of November 27, 2002 by and among GulfTerra Energy Partners, L.P., GulfTerra Energy Finance Corporation, the Subsidiary Guarantors named therein and JPMorgan Chase Bank, as Trustee (Exhibit 4.I to our Current Report on Form 8-K dated December 11, 2002); First Supplemental Indenture dated as of January 1, 2003 (Exhibit 4.I.1 to our Current Report on Form 8-K dated March 19, 2003).
*4.I.1	— Second Supplemental Indenture dated as of June 20, 2003, to the Indenture dated as of November 27, 2002 by and among GulfTerra Energy Partners, L.P., GulfTerra Finance Corporation, the Subsidiary Guarantors named therein and JPMorgan Chase Bank, as Trustee.
4.J	— A/B Exchange Registration Rights Agreement by and among GulfTerra Energy Partners, L.P., GulfTerra Energy Finance Corporation, the Subsidiary Guarantors party thereto, J.P. Morgan Securities, Inc., Goldman Sachs & Co., UBS Warburg LLC and Wachovia Securities, Inc. dated as of March 24, 2003 (Exhibit 4.J to our Quarterly Report on Form 10Q, dated May 15, 2003).
4.K	— Indenture dated as of March 24, 2003 by and among GulfTerra Energy Partners, L.P., GulfTerra Energy Finance Corporation, the Subsidiary Guarantors named therein and JPMorgan Chase Bank, as Trustee dated as of March 24, 2003 (Exhibit 4.K to our Quarterly Report on Form 10Q dated May 15, 2003).
*4.K.1	— First Supplemental Indenture dated as of June 20, 2003, to the Indenture dated March 24, 2003 by and among GulfTerra Energy Partners, L.P., GulfTerra Energy Finance Corporation, the Subsidiary Guarantors named therein and JPMorgan Chase Bank as Trustee.
*4.L	— Indenture dated as of July 3, 2003, by and among GulfTerra Energy Partners, L.P., GulfTerra Energy Finance Corporation, the Subsidiary Guarantors named therein and Wells Fargo Bank, National Association, as Trustee.
*4.M	— A/B Exchange Registration Rights Agreement dated as of July 3, 2003, by and among GulfTerra Energy Partners, L.P., GulfTerra Energy Finance Corporation, the Subsidiary Guarantors named therein, J.P. Morgan Securities Inc., Banc One Capital Markets, Inc., BNP Paribas Securities Corp., Credit Lyonnais Securities (USA) Inc., Credit Suisse First Boston LLC, Fortis Investment Services LLC, The Royal Bank of Scotland plc, Scotia Capital (USA) Inc., SunTrust Capital Markets, Inc. and Wachovia Securities, LLC.
10.A	— General and Administrative Services Agreement dated May 5, 2003 by and among DeepTech International Inc., GulfTerra Energy Company, L.L.C. and El Paso Field Services, L.P. (Exhibit 10.A to our Current Report on Form 8-K dated May 14, 2003.
10.L+	— 1998 Unit Option Plan for Non-Employee Directors Amended and Restated effective as of April 18, 2001. (Exhibit 10.1 to our 2001 Second Quarter 10-Q).
*10.L.1+	— Amendment No. 1 to the 1998 Unit Option Plan for Non-Employee Directors effective as of May 15, 2003.
10.M+	— 1998 Omnibus Compensation Plan, Amended and Restated, effective as of January 1, 1999 (Exhibit 10.9 to our 1998 Form 10-K); Amendment No. 1 dated as of December 1, 1999 (Exhibit 10.8.1 to our 2000 Second Quarter Form 10-Q).

Exhibit Number		Description
*10.M.1+	—	Amendment No. 2 to the 1998 Omnibus Compensation Plan dated as of May 15, 2003.
*31.A	—	Certification of Chief Executive Officer, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
*31.B	—	Certification of Chief Financial Officer, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
*32.A	—	Certification of Chief Executive Officer, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
*32.B	—	Certification of Chief Financial Officer, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.

Undertaking

We hereby undertake, pursuant to Regulation S-K Items 601(b), paragraph (4)(iii), to furnish to the U.S. Securities and Exchange Commission, upon request, all constituent instruments defining the rights of holders of our long-term debt not filed herewith for the reason that the total amount of securities authorized under any such instruments does not exceed 10 percent of our total consolidated assets.

(b) Reports on Form 8-K

We filed a current report on Form 8-K dated May 16, 2003 to file exhibits to the Registration Statement on Form S-3 (Registration No. 333-81772), relating to the issuance of 1,118,881 Common Units and 80 Series F convertible units.

We filed a current report on Form 8-K dated June 6, 2003 to file exhibits to the Registration Statement on Form S-3 (Registration No. 333-81772) relating to our public offering of 1,150,000 Common Units (including the Underwriters' over-allotment option to purchase 150,000 Common Units).

We filed a current report on Form 8-K dated July 1, 2003 to report the pricing of our $250 million Senior Unsecured Notes.

We filed a current report on Form 8-K dated July 14, 2003 to announce the completion of agreements to form a 50/50 joint venture with Valero Energy Corporation in the Cameron Highway Oil Pipeline System project and to announce the completion of a non-recourse financing for the project.

We also furnished information to the SEC on Current Reports on Form 8-K under Item 9 and Item 12. Current Reports on Form 8-K under Item 9 and Item 12 are not considered to be "filed" for purposes of Section 18 of the Securities and Exchange Act of 1934 and are not subject to the liabilities of that section.

SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

GULFTERRA ENERGY PARTNERS, L.P.

By: GULFTERRA ENERGY COMPANY, L.L.C., its General Partner

Date: August 12, 2003

By: /s/ KEITH B. FORMAN

Keith B. Forman
Vice President and Chief Financial Officer
(Principal Financial Officer)

Date: August 12, 2003

By: /s/ KATHY A. WELCH

Kathy A. Welch
Vice President and Controller
(Principal Accounting Officer)

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*3.B.1	— Fourth Amendment dated July 23, 2003, to the Second Amended and Restated Agreement of Limited Partnership.
4.C	— Registration Rights Agreement dated as of August 28, 2000 by and between Crystal Gas Storage, Inc. and GulfTerra Energy Partners, L.P. (Exhibit 4.3 to our 2000 Form 10-K).
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